



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8

1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
<http://www.epa.gov/region08>

OCT 01 2010

Ref: 8P-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Joseph D. Kiolbasa, City Manager
City of Sterling, Colorado
421 N 4th Street, PO Box 4000
Sterling, CO 80751-0400

RE: FINAL Permit
EPA UIC Area Permit CO12163-00000
Sterling Deep Disposal Well Project
Class I Non-Hazardous Disposal Wells
Logan County, Colorado

Dear Mr. Kiolbasa:

Enclosed is your copy of the Environmental Protection Agency (EPA) Region 8 Underground Injection Control (UIC) FINAL Permit for the Sterling Deep Disposal Well Class I Non-hazardous Area Permit. A Statement of Basis that discusses the conditions and requirements of this EPA UIC Permit is also included.

The Public Comment period ended on September 26, 2010. We received no comments on the Draft Permit during the Public Notice period. Since no comments were received during the public comment period, and no changes have been made to the Draft Permit, the Final Permit becomes effective immediately on the date of issuance per Title 40 Code of Federal Regulations (40 CFR) Section 124.18. All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations (CFR) and are regulations that are in effect on the date that this Permit becomes effective.

Please note that under the terms of the Final Permit, you are authorized only to construct the proposed injection well and must fulfill the "Prior to Commencing Injection" requirements of the Permit, Part II Section C Subpart 1, and obtain written Authorization to Inject prior to commencing injection. It is your responsibility to be familiar with and to comply with all provisions of the Final Permit.

Enclosures: Final UIC Permit
Statement of Basis

cc:

Mr. Courtney Hemenway
Hemenway Groundwater Engineering, Inc.
PMB 416
17011 Lincoln Ave
Parker, CO 80134

Mr. Rob Demis, P.E.
Richard P. Arber Associates
198 Union Boulevard, Suite 200
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Ms. Melanie Criswell
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Denise Onyskiw
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UNDERGROUND INJECTION CONTROL
FINAL CLASS I AREA PERMIT

PREPARED: September 2010

Final Area Permit No. CO12163-00000

Class I Non-hazardous Injection Well Area Permit
Sterling Deep Disposal Well Project
Logan County, CO

Issued To

City of Sterling, CO
421 N 4th St, PO Box 4000
Sterling, CO 80751-0400

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Area Permit,

**City of Sterling, CO
421 N 4th St, PO Box 4000
Sterling, CO 80751-0400**

is authorized to construct and to operate the following Class I Non-hazardous injection well project:

Sterling Deep Disposal Well Project Logan County, Colorado

Area Permit Boundary

The area permit is described by the boundary enclosing the entirety of Sections 22, 23, 27, and the north ½ of Section 34, in Township 8 North, Range 52 West, Logan County, Colorado.

Well Locations

This area permit authorizes the construction and operation of two disposal wells within the project described above. These wells are located as follows:

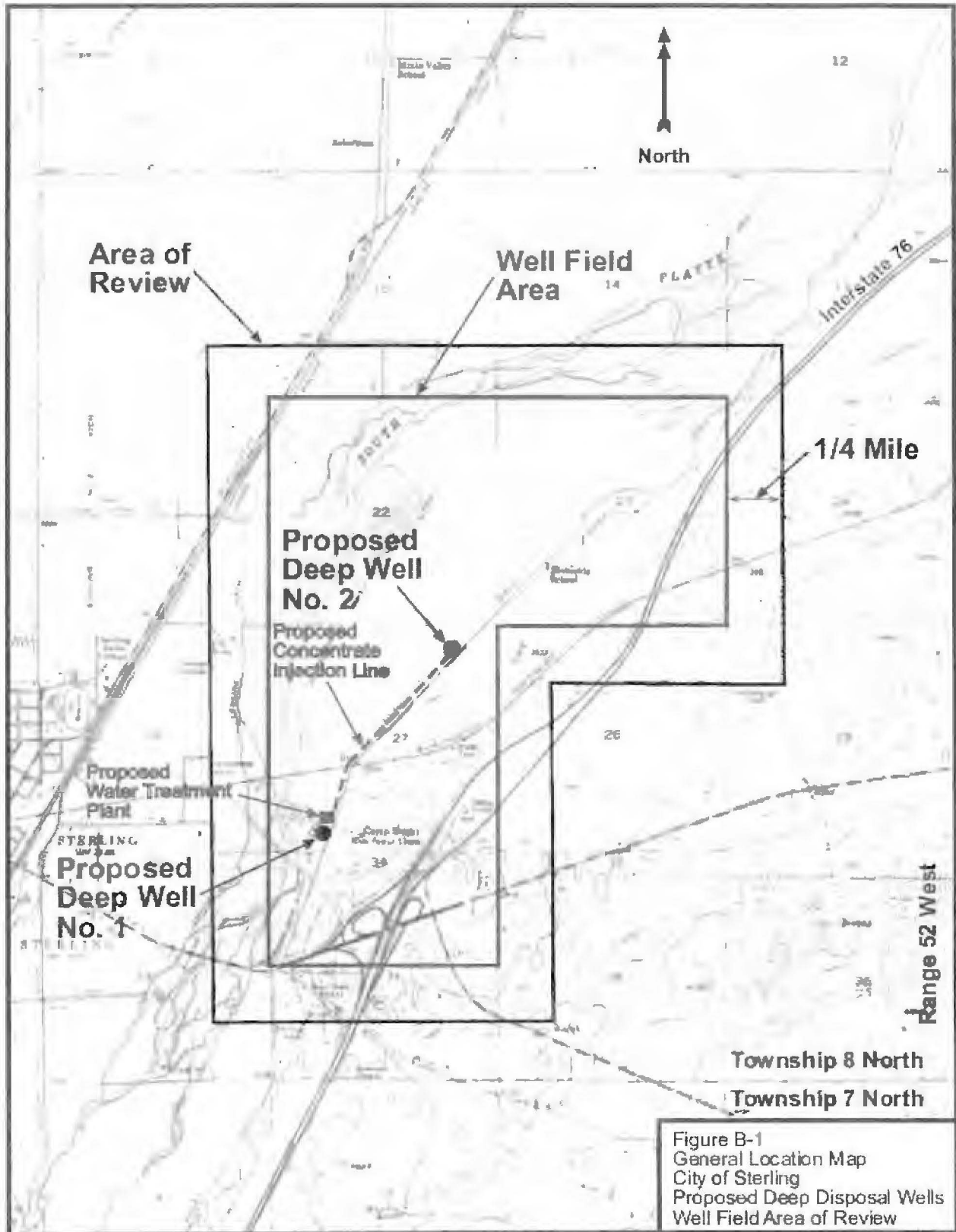
Well Name	UIC Well ID	Proposed Location
Sterling Deep Disposal Well No. 1	CO08741	390 FSL, 1020 FWL, S27, T8N, R52W, Logan County, CO
Sterling Deep Disposal Well No. 2	CO08742	1200 FNL, 1380 FEL, S27, T8N, R52W, Logan County, CO

The map on the following page illustrates the boundary of the area permit boundary (shown in red as “Well Field Area”), the area of review (shown in black as “Area of Review”), the location of the proposed water treatment plant, and the location of the two injection wells.

Permit requirements herein are based on regulations found in 40 CFR Parts 124, 144, 146, and 147, which are in effect on the Effective Date of this Permit.

This Permit is based on representations made by the applicant and on other information contained in the Administrative Record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. This Permit will be reviewed periodically to determine whether action under 40 CFR 144.36(a) is required.

Sterling Deep Disposal Well Area Permit



Sterling Deep Disposal Well Area Permit

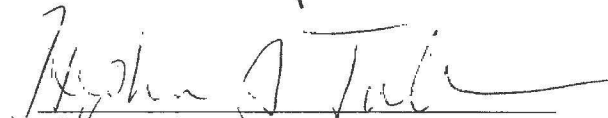


This Permit is issued for a period of ten (10) years unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. This Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for this program is delegated to an Indian Tribe or a State. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions shall be directed to the Indian tribe or State Program Director or designee.

Issue Date: SEP 30 2010

Effective Date: SEP 30 2010

Expiration Date: September 30, 2020



Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size described in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth described in APPENDIX A. The packer setting depth may be changed provided it remains below the depth described in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

- (a) Sampling taps conveniently located and isolated by shut-off valves, to enable collection of representative samples of the fluid in the injection tubing and in the tubing-casing annulus (annulus); and
- (b) One-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:
 - (i) on the injection tubing; and
 - (ii) on the annulus; and
- (c) Continuous recording devices located to monitor and record injection pressure, annulus pressure, flow rate, and volume
- (d) An automated shut-off device set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure specified in APPENDIX C is reached at the wellhead; and

Additional monitoring and sampling devices may be described in APPENDIX A.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Postponement of Construction or Conversion

The Permittee shall construct and complete at least one of the two originally permitted wells within one year of the Effective Date of the Permit, or in the case of an additional well added to this Area Permit, within one year of authorization of the additional well.

Authorization to construct and operate shall expire if at least one of the two originally permitted wells has not been constructed and completed within one year of the Effective Date of the Permit or authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate can be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Internal Mechanical Integrity (Part I MI) is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

7. Annual Pressure Falloff Test

The Permittee must perform a pressure falloff test at least once every twelve months. The pressure falloff test is required for Class I operations [40CFR 146.13(d)(1)] to monitor pressure buildup in the injection zone, to monitor reservoir parameters, to identify any fracturing, and to identify any boundaries within the injection formations.

The Permittee is required to prepare a plan for running the yearly falloff test. EPA Region 6 has developed a set of guidelines that should be used by the Permittee when developing a site specific plan. Region 6 "UIC Pressure Falloff Testing Guideline" is available from EPA and will be provided upon request. The final test plan shall be submitted to Region 8 for review at least 30 days prior to conducting the annual pressure falloff test.

It is important that the initial and subsequent tests follow the same test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. The Permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report shall also compare the test results with previous years test data, unless it is the first test performed at that well, and shall be prepared by a knowledgeable analyst.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

- (a) There is no significant leak in the casing, tubing, or packer (Part I MI); and
- (b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II MI).

1. Demonstration of Mechanical Integrity (MI).

The Permittee shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both Internal Mechanical Integrity (Part I MI) and External Mechanical Integrity (Part II MI) as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of Mechanical Integrity, the Permittee shall demonstrate Internal Mechanical Integrity (Part I MI) following any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the Permittee are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Current copies of Ground Water Section Guidance No. 34 - "Cement Bond Logging Techniques and Interpretation," Ground Water Section Guidance No. 35 - "Procedures to follow when excessive annular pressure is observed on a well," Ground Water Section Guidance No. 37 - "Demonstrating Part II (External) Mechanical Integrity," Ground Water Section Guidance No. 39 - "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity," and "Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations " are provided at issuance of this Permit.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operations.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any regularly scheduled mechanical integrity test. When the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit), and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

The annulus valve shall remain closed during normal operating conditions and the annulus pressure shall be

maintained at zero (0) psi.

If the annulus pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 “Procedures to follow when excessive annular pressure is observed on a well.”

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Injection operation may commence only after all construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until:

- (a) construction is complete, and
- (b) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity (pursuant to 40 CFR 146.8 and Part II, Section B of this Permit) has been demonstrated; and all corrective action requirements (APPENDIX F) have been fulfilled; and
 - (i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or
 - (ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the completion of the above items, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional injection perforations may be added, provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6 of this Permit. In no case shall the operation of the injection well cause the movement of injected or formation fluids outside of the permitted injection interval listed in APPENDIX C.

3. Injection Pressure Limitation

Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall the operation of the injection well cause the movement of injected or formation fluids outside of the permitted injection interval listed in APPENDIX C.

- (a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C.
- (b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permittee may be required to conduct a step rate injection test or other suitable test to provide information for

determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be made by modification of this Permit and APPENDIX C.

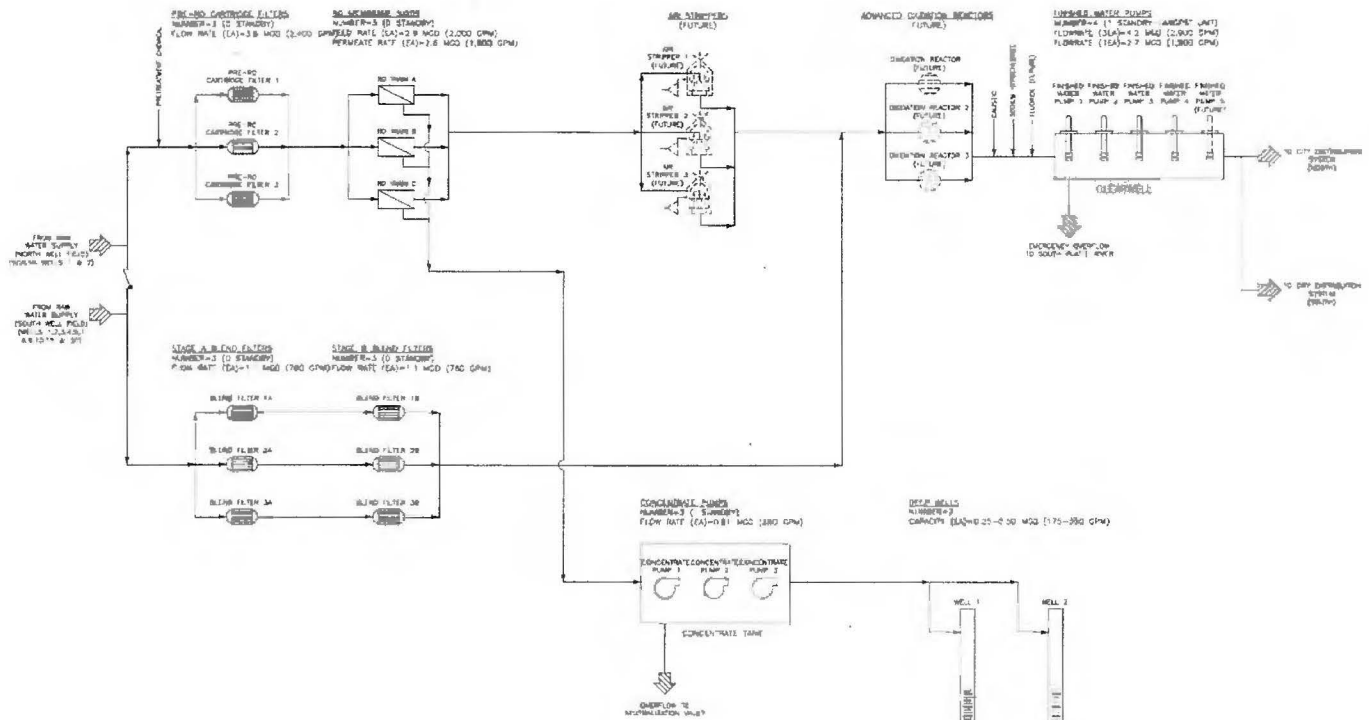
4. Injection Volume Limitation.

Injection volume is limited to the total volume specified in APPENDIX C.

5. Injection Fluid Limitation.

Injection fluid is limited to the concentrated brine generated from the reverse osmosis treatment of raw well water from the city's water treatment plant near the site of the Sterling Deep Injection Well #1. This fluid may be injected into the deep disposal wells only after sample analysis proves that it meets EPA standards for non-hazardous municipal disposal fluids (see APPENDIX D).

This treatment plant receives raw water from the City's water production wells and removes contaminants through a reverse osmosis (RO) process. Approximately 80-90% of the raw water emerges from the RO units as product water for distribution to city residents. The remaining 10-20% of the water from the RO units emerges as concentrated brine that will be disposed deep underground via Sterling's Deep Disposal Wells No. 1 and No. 2. This waste water is required to meet EPA standards for non-hazardous municipal fluids prior to disposal. See the water treatment process, below:



In addition to the concentrated brines from the RO units, additional waste fluids may be generated as a result of periodic cleaning of the RO units. As salts concentrate on the high pressure side of the membrane, the very small pores of the membrane may become plugged. Organic compounds can also plug the pores. As a result of this plugging, the flow decreases and the membrane must be cleaned. To maintain efficiency of the RO units, a volume of water is circulated on the high pressure side of the system with a cleaning agent (for hardness or organic plugging) until the membrane is flushed clean.

Prior to introducing this flush fluid to the RO units, it is expected to fall within a pH range of 2.5 to 12. After it is removed from the RO units, this flush fluid will be neutralized prior to disposal. This fluid may be injected into the deep disposal wells only after sample analysis proves that it meets EPA standards for non-hazardous municipal disposal fluids (see the permit, APPENDIX D).

6. *Tubing-Casing Annulus (annulus)*

The annulus shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The annulus valve shall remain closed during normal operating conditions and the annulus pressure shall be maintained at zero (0) psi.

If the annulus pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

1. *Seismicity*

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service which reports real-time earthquake events for any area specified by the user. The permittee is required to subscribe to this service, known as the Earthquake Notification Service (ENS). Details for the ENS can be found at:

<https://sslearthquake.usgs.gov/ens/>

and a subscription can be initiated at:

<https://sslearthquake.usgs.gov/ens/register>

For any seismic event reported within two miles of the permit boundary, the permittee shall immediately cease injection and report to EPA within twenty-four (24) hours according to Part III, Section E.11. of this permit.. Injection shall not resume until the Permittee has obtained approval to recommence injection from EPA.

For any seismic event occurring between two and fifty miles of the permit boundary, that event will be recorded and reported to EPA on a quarterly basis.

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. *Monitoring Parameters, Frequency, Records and Reports.*

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

- (a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;
- (b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;
- (c) the analytical techniques or methods used for analysis.

2. *Monitoring Methods.*

- (a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

- (b) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.
- (c) Pressures are to be measured in pounds per square inch (psi).
- (d) Fluid volumes are to be measured in standard oilfield barrels (bbl).
- (e) Fluid rates are to be measured in barrels per day (bbl/day).

3. *Records Retention.*

- (a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.
- (b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.
- (c) The Permittee shall retain records at the location designated in APPENDIX D.

4. *Quarterly Reports.*

Whether the well is operating or not, the Permittee shall submit Quarterly Reports to the Director summarizing the results of the monitoring required by Part II Section D and APPENDIX D. Reporting periods and due dates for Quarterly Reports are shown in APPENDIX D. EPA Form 7520-11 may be copied and shall be used to submit the Quarterly Reports, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. *Notification of Well Abandonment, Conversion or Closure.*

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. *Well Plugging Requirements*

Prior to abandonment, the injection well shall be plugged with cement in a manner which prevents the movement of fluids into or between underground sources of drinking water. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director. The well shall be plugged in accordance with the approved plugging and abandonment plan and with 40 CFR 146.10.

3. *Approved Plugging and Abandonment Plan.*

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. *Forty Five (45) Day Notice of Plugging and Abandonment.*

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abandonment plan.

5. *Plugging and Abandonment Report.*

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

- (a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or
- (b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. *Inactive Wells.*

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

- (a) Provides written notice to the Director;
- (b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and
- (c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class I injection well to a non-Class I well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the Permittee changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions

as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging, or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part II, Section B of this permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information).

Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Continuation of Expiring Permits.

- (a) Duty to Reapply. If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must submit a complete application for a new permit at least 180 days before this permit expires.
- (b) Permit Extensions. The conditions of an expired permit may continue in force in accordance with 5 U.S.C. 558(c) until the effective date of a new permit, if:
 - (i) The Permittee has submitted a timely application which is a complete application for a new permit; and
 - (ii) The Director, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

- (c) Enforcement. When the Permittee is not in compliance with the conditions of the expiring or expired permit the Director may choose to do any or all of the following:
- (i) Initiate enforcement action based upon the permit which has been continued;
 - (ii) Issue a notice of intent to deny the new permit. If the permit is denied, the owner or Permittee would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit;
 - (iii) Issue a new permit under part 124 with appropriate conditions; or
 - (iv) Take other actions authorized by these regulations.
- (d) State Continuation. An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State has primary enforcement authority. A State authorized to administer the UIC program may continue either EPA or State-issued permits until the effective date of the new permits, if State law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State-issued new permit.

3. *Need to Halt or Reduce Activity Not a Defense.*

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. *Duty to Mitigate.*

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. *Proper Operation and Maintenance.*

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate Permittee staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. *Permit Actions.*

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. *Property Rights.*

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. *Duty to Provide Information.*

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. *Inspection and Entry.*

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

- (a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;
- (b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
- (c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,
- (d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

- (a) **Planned changes.** The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.
- (b) **Anticipated noncompliance.** The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
- (c) **Monitoring Reports.** Monitoring results shall be reported at the intervals specified in this Permit.
- (d) **Compliance schedules.** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.
- (e) **Twenty-four hour reporting.** The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:
 - (i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or
 - (ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

- (f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website <http://www.nrc.uscg.mil/index.htm>.
- (g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.
- (h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

- (a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or
- (b) suspension or revocation of the authority of the trustee institution to act as trustee; or
- (c) the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or Permittee as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A WELL CONSTRUCTION DETAILS

Sterling Deep Disposal Wells No. 1 and No. 2 (depths approximate):

Hole, Casing, and Cement:

- 12-1/4" hole drilled to 1000 ft.
- 9-5/8" Surface Casing set to a depth of 1000 ft., cemented to surface
- 8-3/4" hole drilled to Precambrian (approx 6989 ft.).
- 7" Longstring Casing set to total depth (approx 6989 ft.), cemented to surface

Perforations:

- The proposed injection zones exist in the Paleozoic interval between the depths of 5261 ft. and 6989 ft. (approx.) below ground level. Since there is little nearby well control that can be used to accurately predict the depths and suitability of injection zones, specific injection zones will be identified and approved only after the well is drilled and logged, after formation fluids are sampled, and after rock characteristics are determined.
- Injection zones and perforated intervals will only be permitted for a formation:
 - 1) existing below all known USDWs; and,
 - 2) separated from USDWs by a competent confining interval; and,
 - 3) isolated from USDWs by adequate casing and cement.
- Suitability for perforated injection intervals will be determined based on results of formation water sample analysis, well logging and testing results, and the adequacy of casing and cementing to prevent USDW contamination.

Tubing and Packer:

- Injection will take place through a tubing string set on packer which is set no more than 100 ft. above the top perforation.

Wellhead and Surface Equipment:

- Sampling taps located to enable sampling the fluid in the injection tubing and in the annulus
- Pressure gauges isolated by 1/2" FIP shut-off valve or quick-connect located to enable reading pressure on the injection tubing and on the annulus
- Continuous recording devices located to monitor and record injection pressure, annulus pressure, flow rate, and injected fluid volume.
- A crown valve on the wellhead that will allow a lubricator and well logging equipment to be rigged up and run into the well while the well remains on injection.
- An automatic shut-in device designed and set to shut in injection operations before operating pressures exceed the Maximum Allowable Operating Pressure (MAIP).

(see schematic on the following page)

APPENDIX A WELL CONSTRUCTION DETAILS

PERMIT REVIEW WORKSHEET

WELL NAME Sterling Deep Injection #1 OPERATOR City of Sterling, Co

S 27 T 8N R 53E Logan COUNTY, CO

CATEGORY : ☐ RA ☒ NEW CONSTRUCTION ☐ NEW CONVERSION from _____

LOCATION : ☐ U/O ☐ WR ☐ SU ☐ UM ☐ MT-IND ☐ MT-NON IND

WELL TYPE : ☐ EOR ☐ NON-COMMERCIAL SWD ☐ COMMERCIAL SWD x CLASS I

DEPTH*	GEOLOGY	SCHEMATIC	DETAILS	LOGS	TESTS	C/A	WELLHEAD EQUIP	OPERATION
0	0			<input type="checkbox"/> CBL/VDL/ γ -RAY	<input type="checkbox"/> PORE PRESSURE	<input type="checkbox"/> PRESSURE LIMIT	<input type="checkbox"/> GAUGES	<input type="checkbox"/> COMPLETION RPT
1	200			<input type="checkbox"/> OAL	<input type="checkbox"/> PERMEABILITY	<input type="checkbox"/> REMEDIAL CMT	<input type="checkbox"/> STAB GAUGES	<input type="checkbox"/> WORKOVER RPT
2	400			<input type="checkbox"/> CASING INSP	<input type="checkbox"/> IZ SAMPLE		<input type="checkbox"/> FLOWMETER	<input type="checkbox"/> AE
3	600			<input type="checkbox"/> RTS	<input type="checkbox"/> SOURCE SAMPLE		<input type="checkbox"/> RATE INDICATOR	<input type="checkbox"/> Vmax _____
4	800			<input type="checkbox"/> TEMP	<input type="checkbox"/> SRT		<input type="checkbox"/> SAMPLE TAP	<input type="checkbox"/> Pmax _____
5	1000			<input type="checkbox"/> DIL	<input type="checkbox"/> MIT			<input type="checkbox"/> MON _____
6	1200			<input type="checkbox"/> γ -RAY				<input type="checkbox"/> RPT _____
7	1400			<input type="checkbox"/> RESISTIVITY				
8	1600			<input type="checkbox"/> CONDUCTIVITY				
9	1800			<input type="checkbox"/> SP				
10	2000			<input type="checkbox"/> SONIC (ϕ)				
11	2200			<input type="checkbox"/> N-DENSITY				
12	2400			<input type="checkbox"/>				
13	2600							
14	2800							
15	3000							
16	3200							
17	3400							
18	3600							
19	3800							
20	4000							
21	4200							
22	4400							
23	4600							
24	4800							
25	5000							
26	5200							
27	5400							
28	5600							
29	5800							
30	6000							
31	6200							
32	6400							
33	6600							
34	6800							
35	7000							
36								
37								
38								
39								
40								
41								
42								
43								
44								

* Depths shown are approximations based on surrounding wells
Actual depths will be determined after logging.

PERMIT NUMBER CO12163-00000

APPENDIX B LOGGING AND TESTING REQUIREMENTS

Logs and Tests

Logging operations will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

Sterling Deep Disposal Wells No.1 and No.2:

Surface Casing Logging Program

TYPE OF LOG	PURPOSE	DUE DATE
Dual Induction	12-1/4" open-hole formation evaluation	Prior to setting 9-5/8" casing
Formation Density	12-1/4" open-hole formation evaluation	Prior to setting 9-5/8" casing
Compensated Neutron	12-1/4" open-hole formation evaluation	Prior to setting 9-5/8" casing
Microlog	12-1/4" open-hole formation evaluation	Prior to setting 9-5/8" casing
Spontaneous Potential	12-1/4" open-hole formation evaluation	Prior to setting 9-5/8" casing
Gamma Ray	12-1/4" open-hole formation evaluation	Prior to setting 9-5/8" casing
Caliper	12-1/4" open-hole cement estimate	Prior to setting 9-5/8" casing
CBL or CET	Cement quality behind the 9-5/8" casing	Prior to setting 7" casing

Longstring Casing Logging Program:

TYPE OF LOG	PURPOSE	DUE DATE
Dual Induction	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Formation Density	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Compensated Neutron	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Microlog	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Spontaneous Potential	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Gamma Ray	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Fracture Finder Log	8-3/4" open-hole formation evaluation	Prior to setting 7" casing
Caliper	8-3/4" open-hole cement estimate	Prior to setting 7" casing
CBL or CET	Cement quality behind the 7" casing	Prior to receiving authorization to inject
Temperature Survey	Baseline formation temperature	Prior to receiving authorization to inject
Temperature Survey	To assess Part II Mechanical Integrity.	Within 6-12 months after beginning injection operations, and at least once every five (5) years after the last successful demonstration of Part II MI
Radioactive Tracer Survey	To assess the ability of the cement to prevent movement of injected fluids out of the approved injection formations.	(only if the CBL or CET fails to show >80% bonding through confining zones) Prior to receiving authorization to inject, and at least once every five (5) years concurrent with the Temperature log as required above.

APPENDIX B LOGGING AND TESTING REQUIREMENTS

Well and Fluid Testing Program:

TYPE OF TEST	PURPOSE	DUE DATE
Injection Formation Pressure	To determine the fluid pressure within each injection formation	Prior to receiving authorization to inject
Injection Formation Water Sample Analysis	To determine TDS content, pH, Specific Gravity, and Specific Conductivity for water within each injection formation	Prior to receiving authorization to inject; performed according to the procedures listed below.*
Injected Fluid Water Sample Analysis	To determine the nature and specific gravity of the injected fluid.	Monthly, until consecutive analyses show that analytes have stabilized, quarterly, after that point, and whenever changes to the treatment system alter the waste stream.
Standard Annulus Pressure Test	To assess Part I Mechanical Integrity	Prior to receiving authorization to inject, following any workover which affects the tubing, packer or casing, and at least once every five (5) years after the last successful demonstration of Part I MI
Pressure Fall-off Test	To determine the pressure buildup in the injection formation	Within the first 6-12 months of operation, and at least once every year thereafter.
Step Rate Injectivity Test	To determine the fracture pressure for each injection formation and to set MAIP.	Prior to receiving authorization to inject

* INJECTION ZONE WATER SAMPLING PROCEDURE

The goal of this procedure is to obtain an uncontaminated representative sample of the naturally occurring formation water within each proposed injection zone in order to determine it's status as a USDW.

Well Preparation and Sampling Procedure

1. The well should be perforated slightly underbalanced in order to prevent wellbore fluids from entering the formation and contaminating the naturally occurring formation water.
2. Sampling should take place prior to any formation stimulation or any other procedure where fluids may enter the formation and contaminate the naturally occurring formation water.
3. Intervals within the same geologic formation may be perforated and sampled together, as long as there is a reasonable expectation that water from those intervals is similar.
4. The sampling procedure should follow immediately after perforating an interval in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water.
5. Sample and analyze the well completion fluid for reference purposes.
6. Swab or foam the well to get a representative fluid sample from the proposed injection interval.
7. Take fluid samples following each tubing volume recovered, measuring the time, volume of fluid recovered, pH, and conductivity.
8. When the pH and conductivity have stabilized during three successive tubing volumes, collect one representative sample for complete water analysis, measuring for TDS, pH, SG, and conductivity.

APPENDIX C OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Except during stimulation, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

Maximum Allowed Injection Pressure (MAIP) will be initially set at 1487 psi (calculated at an injection fluid Specific Gravity less than 1.04, a fracture gradient of 0.733 psi/ft, and an estimated injection formation top of 5261’).

Following well completion and testing, the results from the step rate test and falloff tests will be used to establish formation specific fracture gradients. Additionally, the injected fluid specific gravity will be accurately determined. These two factors will be used to adjust the MAIP, if necessary, so that injection does not initiate new fractures or propagate existing fractures in any of the approved injection zone.

INJECTION INTERVAL(S):

The proposed injection zones are the Paleozoic rock formations between the depths of 5261 ft. and 6989 ft. (approx.) below ground level. Since there is little nearby well control that can be used to accurately predict the depths and suitability of injection zones, specific injection zones will be identified and approved only after the well is drilled and logged, after formation fluids are sampled, and after rock characteristics are determined.

Injection zones and perforated intervals will only be permitted for a formation:

- 1) existing below all known USDWs; and,
- 2) separated from USDWs by a competent confining interval; and,
- 3) isolated from USDWs by adequate casing and cement.

Suitability for perforated injection intervals will be determined based on results of formation water sample analysis, well logging and testing results, and the adequacy of casing and cementing to prevent USDW contamination.

WELL NAME	FORMATION	TARGETED INJECTION INTERVAL (ft)
Sterling Deep Disposal Well No. 1	Paleozoics	5261 – 6989’ (approximate)
Sterling Deep Disposal Well No. 2	Paleozoics	5261 – 6989’ (approximate)

Injection between the outermost casing protecting underground sources of drinking water and the wellbore is prohibited.

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C.2 of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels of fluid that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown above.

APPENDIX C OPERATING REQUIREMENTS

This is a listing of the parameters required to be observed, recorded and reported. Refer to the Permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

CONTINUOUSLY	
MONITOR, OBSERVE AND RECORD	Injection Pressure (psig)
	Annulus Pressure (psig)
	Injection Rate (bbl/day)
	Cumulative Injected Volume (bbl/day)
REPORT	Any seismic events within a 2 mile radius of the area permit boundary, gathered from USGS Earthquake Hazard Program website or through personal communication.

WEEKLY	
ANALYZE	Injection fluid Specific Gravity to maintain below 1.04

MONTHLY	
ANALYZE	Until results stabilize, injectate, according to the methods described in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed on the following page*
REPORT	Until results stabilize, results of injectate analysis.

QUARTERLY	
ANALYZE	Injection fluid total dissolved solids content (mg/l)
	Injection fluid Specific Conductivity
	Injection fluid pH
	Injectate, according to the methods described in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed on the following page*
REPORT	Monthly Average, Maximum, and Minimum values for Injection Pressure (psig)
	Monthly Average, Maximum, and Minimum values for Annulus Pressure (psig)
	Monthly Average, Maximum, and Minimum values for Daily Injection Rate (bbl/day)
	Monthly Average, Maximum, and Minimum values for Injected Fluid Specific Gravity
	Cumulative Volume Injected since the well began injection operations (bbls)
	Results of injectate fluid analysis.
	Summary of monthly reviews of seismic events within a fifty (50) mile radius of the area permit boundary.

	REPORTING PERIOD	REPORT DUE TO EPA
1 st Quarter	January 1 – March 31	May 15
2 nd Quarter	April 1 – June 30	August 15
3 rd Quarter	July 1 – September 30	November 15
4 th Quarter	October 1- December 31	February 15

Records of all monitoring activities must be retained and made available for inspection at the following location:

City of Sterling, CO
205 North Riverview Road
Sterling, CO 80751

APPENDIX D OPERATING REQUIREMENTS

* INJECTATE ANALYSIS

Parameter Analyzed	EPA Analytical Method
Total Dissolved Solids (mg/l)	
Total Suspended Solids (mg/l)	
Specific Conductivity (umhos/cm)	
pH	
Specific Gravity	
Corrosivity Index (Langelier Saturation Index)	
Nitrate-Nitrite (both as N) mg/l	
Sulfate (mg/l)	
Chloride (mg/l)	
Magnesium (mg/l)	
Sodium (mg/l)	
Calcium (mg/l)	
Iron (mg/l)	
Gross Alpha (pCi/l)	E900.0
Gross Beta (pCi/l)	E900.0
Strontium (mg/l)	272.1, 272.2, 200.7
Uranium-234 (pCi/l)	E907.0
Uranium-238 (pCi/l)	E907.0
Thorium-230 (pCi/l)	E907.0
Radium-226 (pCi/l)	E903.0
Radium-228 (pCi/l)	E904.0
Potassium-40 (pCi/l)	E901.1
Lead-210 (pCi/l)	E905.0 Mod.

APPENDIX E
PLUGGING AND ABANDONMENT REQUIREMENTS

Sterling Deep Disposal Wells No.1 and No. 2 (depths approximate):

- Perform Internal Mechanical Integrity Test (Part I)
- Pull Tubing and Packer
- Repair any Casing Leaks
- Circulate well with 9.6 ppg drilling mud or plugging gel
- Squeeze any perforations and place cement in the interval from the TD to a point 100 ft. above the top of the uppermost perforation.
- Set CIBP 50 ft below the base of the lowermost USDW and place 100 ft of cement on top of the CIBP.
- Set CIBP 50 ft below the top of the Niobrara Formation and place 100 ft of cement on top of the CIBP.
- Set CIBP 50 ft. below the base of the surface casing (1050 ft., approx) and place 100 ft of cement on top of the CIBP.
- Set CIBP at the base of the Morrison formation and place 200 ft of cement on top of the CIBP.
- Set CIBP at 100 ft below the base of the Alluvial aquifers and fill the 7" casing from the CIBP to surface.
- Mark wellhead and reclaim surface as required.

(see schematic on the following page)

APPENDIX E PLUGGING AND ABANDONMENT REQUIREMENTS

PERMIT REVIEW WORKSHEET

WELL NAME Sterling Deep Injection #1 OPERATOR City of Sterling, Co
S 27 T 8N R 53E Logan COUNTY, CO

CATEGORY : ☐ RA ☒ NEW CONSTRUCTION ☐ NEW CONVERSION from _____
 LOCATION : ☐ U/O ☐ WR ☐ SU ☐ UM ☐ MT-IND ☐ MT-NON IND
 WELL TYPE : ☐ EOR ☐ NON-COMMERCIAL SWD ☐ COMMERCIAL SWD ☒ CLASS I

DEPTH*	GEOLOGY	SCHEMATIC	DETAILS	
0	0			
1	100' Alluvium		PLUG: 0-200' CIBP @ 200'	LOGS <input type="checkbox"/> CBL/VDL/γ-RAY <input type="checkbox"/> OAL <input type="checkbox"/> CASING INSP <input type="checkbox"/> RTS <input type="checkbox"/> TEMP <input type="checkbox"/> DIL <input type="checkbox"/> γ-RAY <input type="checkbox"/> RESISTIVITY <input type="checkbox"/> CONDUCTIVITY <input type="checkbox"/> SP <input type="checkbox"/> SONIC (φ) <input type="checkbox"/> N-DENSITY <input type="checkbox"/>
2	400			
3	600			
4	800			
5	1000		PLUG: 900-1100' CIBP @ 1100'	
6	1200		9 5/8" to 1000'	
7	1400		Cmt to Surface	
8	1600			
9	1800			
10	2000			
11	2200			TESTS <input type="checkbox"/> PORE PRESSURE <input type="checkbox"/> PERMEABILITY <input type="checkbox"/> IZ SAMPLE <input type="checkbox"/> SOURCE SAMPLE <input type="checkbox"/> SRT <input type="checkbox"/> MIT <input type="checkbox"/>
12	2400			
13	2600			
14	2800			
15	3000			
16	3200			
17	3400			
18	3600		PLUG: 3411-3511' CIBP @ 3511'	
19	3800			
20	4000		DN tool @ 4000'	
21	4200			C/A <input type="checkbox"/> PRESSURE LIMIT <input type="checkbox"/> REMEDIAL CMT
22	4400			
23	4600			
24	4800			
25	5000			
26	5200		PLUG: 5000-5100' CIBP @ 5100'	
27	5400			
28	5600			
29	5800			
30	6000			
31	6200			WELLHEAD EQUIP <input type="checkbox"/> GAUGES <input type="checkbox"/> STAB GAUGES <input type="checkbox"/> FLOWMETER <input type="checkbox"/> RATE INDICATOR <input type="checkbox"/> SAMPLE TAP <input type="checkbox"/>
32	6400			
33	6600			
34	6800			
35	7000			
36				
37				
38				
39				
40				
41				OPERATION <input type="checkbox"/> COMPLETION RPT <input type="checkbox"/> WORKOVER RPT <input type="checkbox"/> AE _____ <input type="checkbox"/> Vmax _____ <input type="checkbox"/> Pmax _____ <input type="checkbox"/> MON _____ <input type="checkbox"/> RPT _____
42				
43				
44				

* Depths shown are approximations based on surrounding wells
 Actual depths will be determined after logging.

PERMIT NUMBER CO12163-00000

APPENDIX F
CORRECTIVE ACTION REQUIREMENTS

CORRECTIVE ACTION:

There are no wells within the area of review which penetrate the confining zone. No corrective action requirements are needed for this permit.



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
<http://www.epa.gov/region08>

STATEMENT OF BASIS

CLASS I INJECTION WELL AREA PERMIT
CITY OF STERLING, CO
STERLING DEEP DISPOSAL WELL PROJECT
LOGAN COUNTY, CO

EPA AREA PERMIT NO. CO12163-00000

CONTACT: Chuck Tinsley
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 6266

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

UIC Permits specify the conditions and requirements for construction, operation, monitoring and reporting, and plugging of injection wells to prevent the movement of fluids into underground sources of drinking water (USDW). Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date, the Permit authorizes the construction and operation of a new injection well project governed by the conditions specified in the Permit. The Permit is issued for a period of ten years unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

City of Sterling, CO
421 N 4th St, PO Box 4000
Sterling, CO 80751-0400

on

January 15, 2010

submitted an application for an Underground Injection Control (UIC) Program Class I Area Permit for the following injection well Project:

Sterling Deep Disposal Well Project
Location: S22, S23, S27, and the N½ of S34, T8N, R52W, Logan County, CO

Regulations specific to Class I injection well operations in the State of Colorado are found at 40 CFR 147 Subpart G.

The Permit application, including the required information and data necessary to issue a UIC Permit in accordance with 40 CFR Parts 124, 144, 146 and 147, was reviewed by EPA and determined to be complete.

These disposal wells are classified as Class I non-hazardous municipal disposal wells.

This Permit is issued for a time period of the (10) years and will expire after that time, or upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the appropriate agency and that agency has the authority and chooses to adopt and enforce this Permit. If the permittee wishes to continue any activity regulated by this permit after the expiration date of this permit, the permittee must submit a complete application for a new permit at least 180 days before the permit expires.

Area Permit Boundary

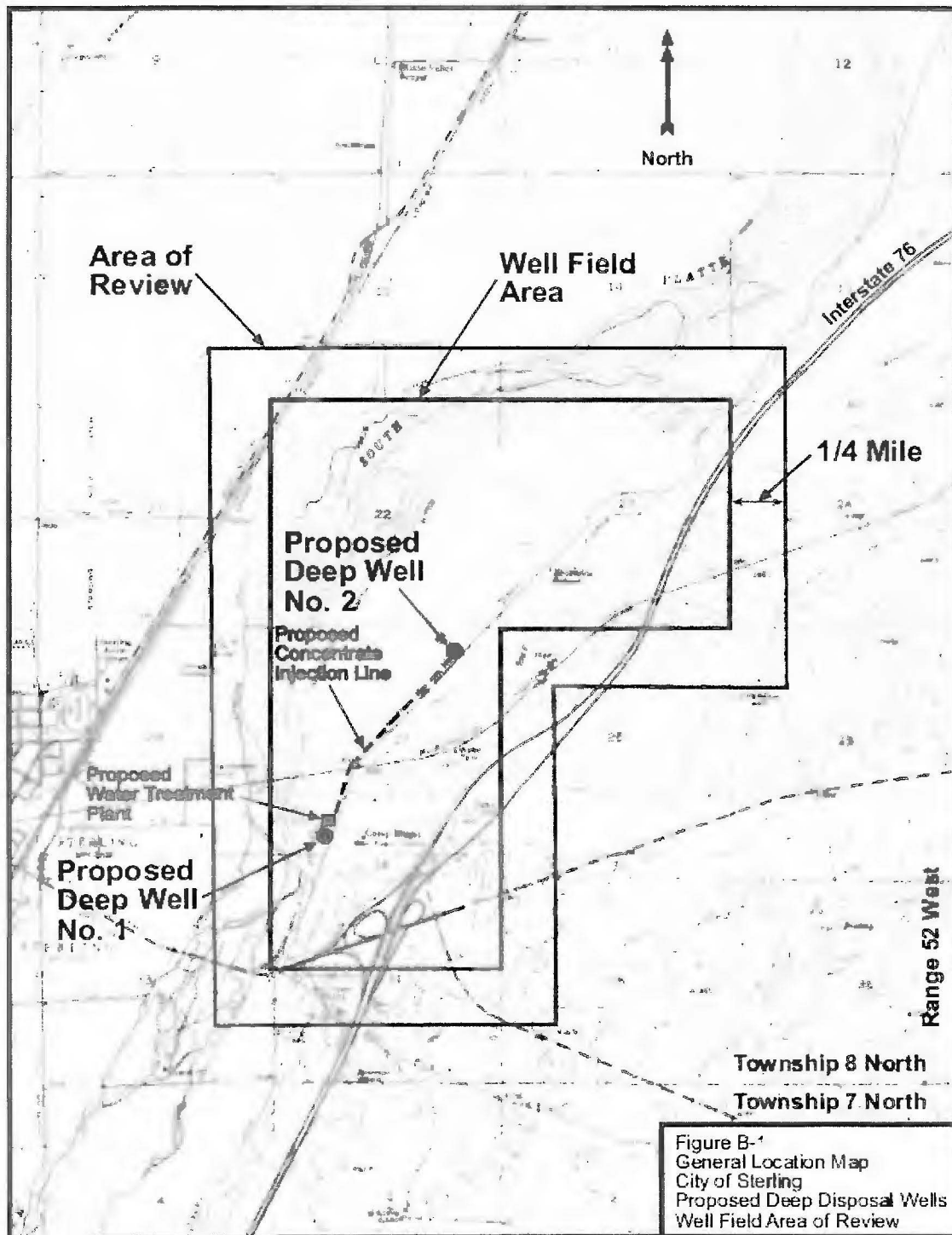
This project is issued as an area permit and is described by the boundary enclosing the entirety of Sections 22, 23, 27, and the north ½ of Section 34, in Township 8 North, Range 52 West, Logan County, Colorado. As part of the review for this permit, an area extending 1/4 mile outside of this project area (Area of Review, or AOR) is studied for potential impacts from injection activities.

Well Locations

This area permit authorizes the construction and operation of two disposal wells within the project described above. These wells are located as follows:

INJECTION WELL ID AND LOCATION		
Well Name	UIC Well ID	Proposed Location
Sterling Deep Disposal Well No. 1	CO08741	390 FSL, 1020 FWL, S27, T8N, R52W, Logan County, CO
Sterling Deep Disposal Well No. 2	CO08742	1200 FNL, 1380 FEL, S27, T8N, R52W, Logan County, CO

Sterling Deep Well Area Boundaries



Sterling Deep Disposal Well Area Boundaries



Background

Sterling Existing Water System

The City of Sterling (Sterling) is located within Logan County approximately 120 miles northeast of Denver along Interstate 76 adjacent to the South Platte River. Sterling's city limits encompass 5.38 square miles. Primary water uses in Sterling include residential, commercial, industrial, and government water use, as well as irrigation. The city water system serves a residential population of approximately 13,900 people and 4,965 service taps. Sterling operates under a Council/Manager form of government.

Sterling obtains its drinking water from 15 alluvial wells in two well fields. Drinking water is pumped from the alluvial wells, is chlorinated, and is conveyed to the distribution system. The Sterling water system has four water storage tanks all within the same pressure zone. Two ground level tanks are located in the West Well Field and have water storage volumes of 7.5 million gallons (MG) and 2.0 MG. Two elevated tanks are located within Sterling (North and South Tanks), and both have a water storage volume of 250,000 gallons each. Sterling has a total of 10 MG of storage within the distribution system. There is one booster pump station in the distribution system. The booster pump station serves the prison and hotels located near Interstate 76. There is no dedicated storage for the pressure zone served by the booster pump station. The distribution system includes a network of 85 miles of transmission and distribution lines. Pipe diameters in the system range from 6 inches to 24 inches.

Irrigation for parks, cemeteries, sports fields, and golf courses is supplied by a combination of irrigation-only wells and dedicated irrigation connections to the potable water distribution system. An ethanol plant located in the northeast side of town has two dedicated wells. Water for the ethanol plant is treated with a reverse osmosis (RO) process.

Enforcement Order and Existing Water Quality

The City of Sterling was issued an Enforcement Order (DC-080902-1) by the Colorado Department of Public Health and Environment (CDPHE) on September 2, 2008 related to violations of two National Primary Drinking Water Standards, which are legally enforceable.

1. Sterling's well water supply has elevated concentrations of uranium that exceed the Maximum Contaminant Limit (MCL) of 30 µg/L.
2. Sterling has experienced levels of TTHM, which have occasionally approached and exceeded the MCL of 80 µg/L.

In addition to these violations of the National Primary Drinking Water Standards, Sterling has several other water quality concerns:

1. CDPHE is concerned that the wells should be considered Ground Water Under Direct Influence (GWUDI) of surface water.
2. Several of the wells, in particular those located on the west side of Sterling, have an elevated concentration of nitrate that sometimes approaches, but does not exceed the Primary Standard of 10 mg/L.
3. Sterling's water supply has elevated concentrations of total dissolved solids (TDS), sulfate, and hardness that exceed Secondary Standards (i.e., non-enforceable standards based on aesthetics in lieu of health).

Selected Treatment Process

The alternative selected for implementation in Sterling's water treatment is nanofiltration (NF) with a blend stream filtered. The NF process provides the necessary removal of

Primary Drinking Water contaminants while also treating for Secondary Standards, thereby improving the public acceptability of the finished water, which is a high priority for Sterling.

The projected potable water peak day demand for the year 2022 is 9.6 mgd, and the projected peak day demand for the year 2032 is 10.9 mgd. The capacity of major equipment will be for the year 2022 demands (Phase I). The building, pipelines, and some tanks will be sized for the year 2032 (Buildout) demands.

Role of the Injection Wells

As the treatment plant receives raw water from the city's water production wells, contaminants are removed through a NF process, similar to reverse osmosis (RO). Approximately 80-90% of the volume of raw water emerges from these RO units as product water for distribution to city residents. The remaining 10-20% of the water from the RO units emerges as concentrated brine that will be disposed deep underground via Sterling's Deep Disposal Wells No. 1 and No. 2. All fluids must meet EPA standards for non-hazardous municipal fluids prior to disposal.

More specific details of this process, including a process schematic and specific analytes and methods for fluid analysis are listed later in this Statement of Basis, and in the permit in Appendix D of the permit.

Endangered Species Act Considerations

On April 22, 2010, EPA contacted the U.S. Fish and Wildlife Service (FWS) requesting FWS concurrence on the determination that the Sterling Deep Disposal Well Project would have No Effect on threatened, endangered, proposed, or candidate species. A return email was received indicating the FWS position that that this project would have no effect on federally protected species.

National Historic Preservation Act Considerations

Section 106 of the National Historic Preservation Act, as amended, requires that federal agencies, in consultation with the State Historic Preservation Officer (SHPO), consider the effect of federally funded or permitted undertakings to cultural resources listed, or eligible for listing, in the National Register of Historic Places.

On April 12, 2010, EPA made an inquiry to Mr. Edward C. Nichols, Colorado State Historic Preservation Officer, requesting any information regarding the existence of any historic sites within the permit area boundary. Mr. Nichols responded that in his opinion, no historic properties will be affected by the Sterling Deep Disposal Well Project and the project may proceed without additional cultural resources inventory.

REGIONAL GEOLOGY AND STRATIGRAPHY

The lithology and nomenclature for the geologic formations expected to be encountered when drilling the Sterling Deep Disposal Wells are relatively well defined and consistent due to the number of wells currently drilled through those formations. This includes wells drilled into the shallow alluvial aquifer system of the South Platte River and by the oil and gas wells drilled into the producing zones of Cretaceous period Colorado and Dakota Groups. There are some minor variations in lithological descriptions within the Colorado and Dakota Groups.

For the deeper zones (proposed for injection) of the Permian and Pennsylvanian period, the lithological nomenclature is variable with respect to the time and location at which the well logs were interpreted. This is evident in logged oil and gas wells that were completed in different areas of Logan County over various time frames and for various geologic studies and reports that have attempted to identify regional geology. These lithological descriptions vary between the well logs presented and in regional geologic studies and reports.

During review of the geologic data for this permit application, Colorado Oil and Gas Conservation Commission (COGCC) records were accessed, which detail the construction details and the geologic formations encountered during the drilling and completion of all oil and gas wells within the project Area of Review (AOR).

Formation names consistent with the Rocky Mountain Association of Geologists (RMAG) publication are used in this Statement of Basis and in the permit for the Sterling injection wells. The geologic formation names which are listed in the COGCC reports, when different, were made consistent with those listed in the RMAG Special Publication No. 2, "Subsurface Cross Sections of Colorado."

The oil and gas wells encountered within the AOR were used to estimate the formations and their depths, which are expected to be encountered during the drilling of the Sterling injection wells. In order to determine the anticipated depths of geologic formations below those encountered in the AOR wells, COGCC records were accessed for the closest wells outside of the AOR, which were drilled to depths approaching that of the proposed injection wells. Formation thickness estimates were calculated from these deeper formations and adjustments were made to those estimates based on the anticipated thickening or thinning of formations as they approach the site of the proposed Sterling injection wells.

The wells used to estimate deeper formation thickness at the site of the Sterling injection wells are shown in the map below. Each well is labeled with the well's API number, and the well's total depth (TD).

Nearby Deep Wells Used to Estimate Formation Thickness



Local Geology and Estimates of Formation Depth

The geologic formations expected to be encountered during the drilling of the Sterling injection wells are described below. As noted above, nearby oil and gas well data was used to provide these estimates. When applicable, formation names were made consistent with those used in RMAG Special Publication No. 2, "Subsurface Cross Sections of Colorado."

As an aid to this discussion, the figure at right shows a generalized stratigraphic column for the Denver-Julesburg Basin in Colorado. This stratigraphic column, which was provided by Colorado Geologic Survey hydrologist Ralf Topper, closely represents the stratigraphy as listed in the RMAG publication.

Alluvium (0' - 100')

Exposed to the surface and situated on top of the Pierre Shale, the uppermost formation is the Quaternary alluvium within the paleochannel of the South Platte River. The alluvium is continuous along the alignment of the South Platte River and is found over the entire AOR. The South Platte River alluvium is approximately eight miles wide along the river axis at the AOR and generally ranges in depth from 25 to 130 ft. thick. At the site of an oil well adjacent to the proposed Sterling Deep Disposal Well #1, the alluvium is 100 ft. thick.

Pierre (100' - 3461')

The Pierre shale is a widespread silty, dense marine shale extending to a depth of 3461 ft. thick at this project site. The uppermost section of this formation is an olive-gray, clayey marine shale with thin discontinuous lenses of siltstone and very fine grained sandstone. These slightly permeable lenses subcrop the dune sand where the dipping beds are beveled by erosion and may be recharged by precipitation percolating through the dune sand. The thin siltstone and sandstone lenses of the upper Pierre may produce water yields of highly mineralized, soft water.

Niobrara and Codell (3461' - 3852')

Composed of two members, the Ft. Hays and Smoky Hill, the Niobrara is a shale and limestone formation. The facies relationship between the Pierre and Niobrara formations is well shown on RMAG cross-sections. The Codell overlies and marks the top of the Carlile formation.

Carlile (3852' - 4057')

This formation marks the upper member of the Colorado Group and consists of shale, limestone, sandstone and siltstone. RMAG Publication No. 2 mentions the Codell as the upper member of the Carlile formation along with the deeper Fairport and Blue Hill members.

Greenhorn (4057' - 4201')

This shale and limestone formation is composed of three members, the Lincoln, Hartland, and Bridge Creek.

ERA	PERIOD	DENVER-JULESBURG BASIN
CENOZOIC	PLIOCENE	Ogallala Fm
	MIOCENE	Arikaree Grp
	OLOGCENE	White River Fm
	EOCENE	
	PALEOCENE	Clayton Fm Denver Fm Arapahoe Fm
MESOZOIC	UPPER CRETACEOUS	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
		Fort Union Fm
		Dakota Fm
		Mudstone Fm
		Pierre Fm
	LOWER CRETACEOUS	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
		Fort Union Fm
		Dakota Fm
		Mudstone Fm
		Pierre Fm
	JURASSIC	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
	TRIASSIC	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
PALEOZOIC	PERMIAN	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
		Fort Union Fm
		Dakota Fm
		Mudstone Fm
		Pierre Fm
	TRIASSIC	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
		Fort Union Fm
		Dakota Fm
		Mudstone Fm
		Pierre Fm
PRECAMBRIAN	DEVONIAN	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
		Fort Union Fm
		Dakota Fm
		Mudstone Fm
		Pierre Fm
	PRECAMBRIAN	Fort Union Fm Dakota Fm Mudstone Fm Pierre Fm Cretaceous Sh
		Fort Union Fm
		Dakota Fm
		Mudstone Fm
		Pierre Fm

The top of the Graneros Formation contains a bentonite, commonly referred to as the X marker. This bentonite has good regional extent and is easily identified on well logs.

The Cretaceous age Dakota Group lies in the interval between 4295 feet and 4930 feet below ground surface. This group consists of, in descending order, the upper "D" and "J" Sandstone members, the middle Skull Creek Shale member, and the basal Plainview-Lytle Sandstone member.

The unconformable systemic boundary between the Lytle Formation and the underlying Jurassic age Morrison Formation is generally indistinguishable on well logs. The base of the lowest sandstone by log signature is commonly used as the boundary of convenience. Both formations are primarily of continental origin and contain common sandstone and shale lithologies.

The Morrison Formation consists of variegated shale and siltstone, with interbedded limestone and sandstone beds. The Morrison is a very shallow, low-energy marine sequence noted for its vertebrate fauna. The Morrison is expected to serve as a primary confining zone serving to limit migration of fluids injected into the deeper Paleozoic targets and the known USDWs existing above the Morrison Formation.

The Entrada, if present, is a buff to reddish, well-sorted and frequently cross-bedded fine sandstone. It represents beach sands, probably eolian in part; correlative with basal Sundance and Nugget

[illegible]

formations of Wyoming. In the nearby Arco-Sindt #6-15 well (API No. 05-075-09115), the Entrada was seen as having good porosity.

Blaine

In the nearby Arco-Sindt #6-15 well (API No. 05-075-09115), this Permian salt section had a thickness of 62 feet, comparable to nearby wells of this depth. The Permian Lyons and stray sandstones were also noticed in this well, having good to excellent porosity.

Cedar Hills (Top at 5261')

Red sandstone, siltstone, and shale with local evaporites. This formation interfingers locally with overlying Blaine evaporites.

Stone Corral

A massive anhydrite, locally dolomitic. Widely recognizable in the D-J Basin, it is the most commonly picked marker in the south-eastern part of the area.

Wolfcamp (5604' - 6026')

Gray to pink limestone, dolomite, anhydrite with interbedded pink to gray or black shale and siltstone. This formation contains a salt section in the north central part of the D-J Basin. The name Wolfcamp is commonly used as a formation name, as are the Group names Chase and Council Grove to the east. In the north-central part of the basin, the Wolfcamp is separated from the Pennsylvanian System by a lateritic horizon called the "Red Shale Marker."

Virgil (6026' - 6159')

Also known as the Shawnee, the Virgil is the top of the Pennsylvanian and is an interbedded tan to brown, fine to very fine-grained sandstone and light colored oolitic limestone. Terrigenous clastic content increases westward. At the site of the nearby Arco-Sindt #6-15 well (API No. 05-075-09115), the Virgil was described as a light brown, medium crystalline limestone with dark brown oil stain. Fair vuggy porosity was seen in samples. A 53 foot core section showed numerous porosity zones without oil shows.

Lansing/Kansas City (6159' - 6398')

Also called the Missouri in some drilling logs, interbedded cream to dark brown, locally cherty and oolitic limestone and dark gray to black shales with some light gray to buff dolomite and occasional traces of

ERA	PERIOD	DENVER-JULESBURG BASIN
CENOZOIC	PLIOCENE	Ogallala Fm
	MIOCENE	Alamosa Grp
	OLIGOCENE	Wapiti Shale Fm
	Eocene	
	PALEOCENE	Dakota Fm Denver Fm Arapahoe Fm
MESOZOIC	CRETACEOUS	Laurel Fm Pawnee Fm H. H. Fm Sagebrake Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Fort Union Fm
		Fort Union Fm
		Fort Union Fm
		Fort Union Fm
	JURASSIC	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	TRIASSIC	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
PALEOZOIC	PERMIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	PENNSYLVANIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	MISSISSIPPIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	DEVONIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	SILURIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	ORDOVICIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	UPPER CAMBRIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
	PRECAMBRIAN	Wapiti Shale Fm P. H. Fm P. H. Fm P. H. Fm P. H. Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm
		Wapiti Shale Fm

PART II. Permit Considerations (40 CFR 146.24)

Proposed Injection Zone(s)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in the table below.

Injection will only occur into an injection zone that is separated from USDWs by confining zones, which are free of known open faults or fractures within the Area of Review. The proposed injection zones are the Paleozoic rock formations between the depths of 5261 ft. and 6989 ft. (approx.) below ground level. Since there is little nearby well control to accurately predict the depths and suitability of injection zones, specific injection zones will be identified and approved only after the well is drilled and logged, after formation fluids are sampled and USDWs identified, and after rock characteristics are determined.

Injection zones and perforations will only be permitted within a formation:

- 1) existing below all known USDWs; and,
- 2) separated from USDWs by a competent confining interval; and,
- 3) isolated from USDWs by adequate casing and cement.

Suitability for perforated injection intervals will be determined based on results of formation water sample analysis, well logging and testing results, and the adequacy of casing and cementing to prevent USDW contamination.

INJECTION ZONE					
Formation	Top (ft)	Base (ft)	TDS (mg/l)	FG (psi/ft)	Exempted? *
Paleozoic interval	5,261 approx	6,989 approx	>10,000	0.733	N/A

* This item describes the status of any aquifer exemption applicable to this injection zone:

C - Currently Exempted
E - Previously Exempted
P - Proposed
N/A - Not Applicable

Confining Zone(s)

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement out of the injection zone. The 269 ft. thick Morrison Formation will serve as the primary confining zone between injection in the Paleozoic Formations and the overlying USDWs. Since there is little nearby well control to accurately predict the depths and suitability of confining zones, specific confining zones will be identified and approved only after the well is drilled and logged, after formation fluids are sampled, and after rock characteristics are determined. The 3361 ft. thick Pierre Shale will also serve as ample confinement for the shallower water supply wells currently in use in the area.

CONFINING ZONES			
Name	Top (ft)	Base (ft)	Lithology
Pierre Shale	100	3461	Marine Shale
Morrison	4930 approx.	5299 approx.	Shale, siltstone, limestone
Additional Confining Zones			Identified upon well completion

Underground Sources of Drinking Water (USDWs)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. Although several formations in the project area have the potential to serve as USDWs, water quality data is rare for formations below the Pierre Shale. The deepest known USDW in the vicinity of the Sterling injection wells is the Dakota group with samples showing TDS values ranging between 4,405 and 8,793 mg/l TDS. There are several formations existing between the Pierre Shale and the Dakota group that could serve as USDWs, however, there is a lack of water quality information within these formations. They will be considered to be USDWs until proven otherwise. For purposes of this permit, the formations considered to be USDWs are shown in the table below:

UNDERGROUND SOURCES OF DRINKING WATER (USDW)			
Formation Name	Top (ft)	Base (ft)	TDS (mg/l)
Dune Sands/Alluvium	0	100	Indicated as < 10,000
Pierre Sand Lenses	100	660	1,200
Niobrara	3461	3852	Not provided, assumed < 10,000
Greenhorn Limestone	4057	4201	Not provided, assumed < 10,000
Dakota Group	4295	4930	4,405 - 8,793
Additional USDWS			Identified upon well completion

There may be unidentified USDWs existing below the Morrison Formation, and permit conditions require the permittee to sample these formations prior to injection. Any formation below the Morrison identified as containing water with less than 10,000 mg/l TDS will be considered as a USDW and will not be permitted for injection. In addition, the permit will require injection to take place below that formation and will require the existence of an adequate confining zone and adequate well isolation (casing and cement) between any injection zone and the lowermost USDW.

Earthquake Hazards Assessment

The shear stress required to trigger a fault is a function of formation pore pressure. A sufficient increase in pore pressure must exist to reduce the shear stress in the rock to cause a failure. To know *a priori* the pressure that will cause a failure is a formidable task that involves installing a seismic network and flow modeling.

The strongest evidence to date that exists that support the statement that injection is low risk is the current UIC well injection activity in the Wattenberg and Greeley oil fields through which five major wrench faults are located. There are nine saltwater disposal wells, eight enhanced recovery wells, and one Class I injection that currently inject into the Lyons formation and deeper. To date, there has not been any reported seismic activity as a result of these injection activities. Review of the maximum allowable injection pressure (MAIP) and injection history shows that the wells have been authorized to inject up to 3700 psi, however, with the exception of one well actual injection pressure has been below 2500 psi.

Even though the potential for earthquake activity resulting from injection activity is considered low, the permittee, using U.S. Geological Survey (USGS) Earthquake Hazards Program, will be required to monitor earthquakes in the vicinity of the injection wells and to report these occurrences to EPA following detection of any earthquakes in the vicinity. Monitoring and reporting frequency is set as follows:

Continuously

Establish and monitor, using the USGS Earthquake Hazards Program, any seismic activity within fifty miles of the project boundary. Detection of an earthquake within two miles of the project boundary will require ceasing injection immediately and reporting to EPA. Injection activities may be resumed after approval from EPA.

Quarterly

Report all seismic activity within fifty miles of the project boundary to EPA.

PART III. Well Construction, Logging, and Testing

Well Construction Requirements

The approved well completion plans are incorporated into the Permit as APPENDIX A and are binding on the Permittee. Modification of these approved plans is allowed under 40 CFR 144.52(a)(1) provided that approval is obtained from the Director prior to actual modification.

Casing and Cementing

The well construction plans were evaluated and were determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Surface casing is required to be installed from the surface to approximately 1000 ft. and will be fully cemented from bottom to top. Injection casing is required from the surface to the well's total depth at approximately 6989 ft., also fully cemented from bottom to top. Cement quality for both casing strings will be verified by cement bond or cement evaluation type logs. Construction and completion details for the injection wells are shown in the permit as APPENDIX A, and in the schematic below.

PERMIT REVIEW WORKSHEET

WELL NAME Sterling Deep Injection #1 OPERATOR City of Sterling, CO
S 27 T 8N R 53E Logan COUNTY, CO

CATEGORY : ☐ RA ☒ NEW CONSTRUCTION ☐ NEW CONVERSION from _____

LOCATION : ☐ U/O ☐ WR ☐ SU ☐ UM ☐ MT-IND ☐ MT-NON IND

WELL TYPE : ☐ EOR ☐ NON-COMMERCIAL SWD ☐ COMMERCIAL SWD x CLASS I

DEPTH*	GEOLOGY	SCHEMATIC	DETAILS
0	100' Alluvium		
1	200		
2	400		
3	600		
4	800		
5	1000		9 5/8" to 1000' cmt to surface
6	1200		
7	1400		
8	1600		
9	1800		
10	2000		
11	2200		
12	2400		
13	2600		
14	2800		
15	3000		
16	3200		
17	3400		
18	3600		
19	3800		
20	4000		DV tool @ 4000'
21	4200		
22	4400		
23	4600		
24	4800		
25	5000		
26	5200		Tubing set on a packer located no more than 100 ft above the top perforation.
27	5400		
28	5600		
29	5800		
30	6000		
31	6200		
32	6400		Perforated intervals to be determined upon completion
33	6600		
34	6800		
35	7000		7" to Pre Cambrian cmt to surface
36			
37			
38			
39			
40			
41			
42			
43			
44			

* Depths shown are approximations based on surrounding wells
 Actual depths will be determined after logging.

LOGS
<input type="checkbox"/> CBL/VDL/γ-RAY
<input type="checkbox"/> OAL
<input type="checkbox"/> CASING INSP
<input type="checkbox"/> RTS
<input type="checkbox"/> TEMP
<input type="checkbox"/> DIL
<input type="checkbox"/> γ-RAY
<input type="checkbox"/> RESISTIVITY
<input type="checkbox"/> CONDUCTIVITY
<input type="checkbox"/> SP
<input type="checkbox"/> SONIC (φ)
<input type="checkbox"/> N-DENSITY
<input type="checkbox"/>

TESTS
<input type="checkbox"/> PORE PRESSURE
<input type="checkbox"/> PERMEABILITY
<input type="checkbox"/> IZ SAMPLE
<input type="checkbox"/> SOURCE SAMPLE
<input type="checkbox"/> SRT
<input type="checkbox"/> MIT
<input type="checkbox"/>

C/A
<input type="checkbox"/> PRESSURE LIMIT
<input type="checkbox"/> REMEDIAL CMT

WELLHEAD EQUIP
<input type="checkbox"/> GAUGES
<input type="checkbox"/> STAB GAUGES
<input type="checkbox"/> FLOWMETER
<input type="checkbox"/> RATE INDICATOR
<input type="checkbox"/> SAMPLE TAP
<input type="checkbox"/>

OPERATION
<input type="checkbox"/> COMPLETION RPT
<input type="checkbox"/> WORKOVER RPT
<input type="checkbox"/> AE
<input type="checkbox"/> Vmax
<input type="checkbox"/> Pmax
<input type="checkbox"/> MON
<input type="checkbox"/> RPT

PERMIT NUMBER CO12163-00000

Tubing and Packer

Injection shall take place only through tubing installed on a packer. The packer will be set no more than 100' above the uppermost perforated or open hole interval. The tubing and packer shall be designed to prevent injection fluid from coming into contact with the outermost casing and to provide for monitoring the well's mechanical integrity.

Tubing-Casing Annulus (TCA)

The TCA allows for pressure monitoring to assess the integrity of the casing, tubing and packer and allows for periodic pressure-testing for mechanical integrity and leak detection. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director and will be maintained at zero pressure during well operation.

Injection Well Monitoring Devices

The Permittee shall install and maintain in good operating condition:

- (a) Sampling taps conveniently located and isolated by shut-off valves, to enable collection of representative samples of the fluid in the injection tubing and in the tubing-casing annulus; and
- (b) One-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C of the permit:
 - (i) on the injection tubing; and
 - (ii) on the tubing-casing annulus (TCA); and
- (c) Continuous recording devices located to monitor and record injection pressure, annulus pressure, flow rate, and volume
- (d) An automated shut-off device set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure specified in APPENDIX C is reached at the wellhead; and
- (e) A cumulative volume recorder attached to the injection line.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

Well Construction Requirements: Sterling Injection Wells No. 1 and No. 2				
Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12-1/4	9-5/8	0-1000	0-1000
Injection	8-3/4	7	0-6989	0-6989

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S13	118251	NE, NE, Sect. 13, T8N, R52W, 1200N, 560E	Alluvium	53	COMMERCIAL
S13	118251	NE, NW, Sect. 13, T8N, R52W, 1240N, 2070E	Alluvium	80	MUNICIPAL
S13	223997	NE, SW, Sect. 13, T8N, R52W, 1680N, 2763W	Alluvium	103	DOMESTIC, STOCK
S13	24845	NW, NW, Sect. 13, T8N, R52W	Alluvium	55	DOMESTIC
S13	120027	NW, SE, Sect. 13, T8N, R52W, 2049N, 2501E	Alluvium	--	OTHER
S13	120024	SE, NE, Sect. 13, T8N, R52W, 2415S, 6E	Alluvium	73	OTHER
S13	120022	SE, NW, Sect. 13, T8N, R52W	Alluvium	61	OTHER
S13	120026	SE, NW, Sect. 13, T8N, R52W, 1899S, 2061E	Alluvium	67	OTHER
S13	219811	SE, NW, Sect. 13, T8N, R52W, 2600S, 2600E	Alluvium	72	DOMESTIC, STOCK
S13	120028	SE, SE, Sect. 13, T8N, R52W, 881S, 7E	Alluvium	109	OTHER
S13	120025	SE, SW, Sect. 13, T8N, R52W, 796S, 1372E	Alluvium	73	OTHER
S13	274354	SW, NE, Sect. 13, T8N, R52W, 1344S, 1529W	Quaternary Alluvium	75	DOMESTIC, STOCK
S13	120029	SW, SE, Sect. 13, T8N, R52W, 76S, 1528W	Alluvium	73	OTHER
S14	24756	NE, NW, Sect. 14, T8N, 52W	Alluvium	71	DOMESTIC
S14	70795	NE, NW, Sect. 14, T8N, R52W, 380N, 2650W	Alluvium	400	HOUSEHOLD USE ONLY
S14	24844	NW, NE, Sect. 14, T8N, R52W	Alluvium	72	DOMESTIC
S14	6208	NW, NE, Sect. 14, T8N, R52W	Alluvium	80	IRRIGATION
S14	59859	NW, NW, Sect. 14, T8N, R52W, 1307N, 1309W	Alluvium	--	AUGMENTATION
S14	16080	SW, NW, Sect. 14, T8N, R52W, 2255S, 25W	Alluvium	80	STOCK
S14	16080	SW, NW, Sect. 14, T8N, R52W	Alluvium	60	IRRIGATION
S14	94374	SW, NW, Sect. 14, T8N, R52W, 2255S, 40E	Alluvium	--	STOCK
S15	24755	SE, SE, Sect. 15, T8N, R52W	Alluvium	--	Domestic
S15	30754-F	SE, SE, Sect. 15, T8N, R52W, 1162S, 1258E	Alluvium	83	Domestic
S15	13728	SE, SE, Sect. 15, T8N, R52W	Alluvium	60	Stock
S15	25306	SW, SE, Sect. 15, T8N, R52W, 660S, 1340E	Alluvium	78	Stock
S15	125671	SW, SE, Sect. 15, T8N, R52W, 1210S, 2110E	Alluvium	88	Household Use Only
S16	119014	SE, SE, Sect. 16, T8N, R52W	Alluvium	--	--
S21	99792	NE, NE, Sect. 21, T8N, R52W, 1267N, 717E	Alluvium	87	Domestic, Stock
S21	99792	NE, NE, Sect. 21, T8N, R52W, 1267N, 717E	Alluvium	85	Domestic, Stock
S21	184848	NE, NE, Sect. 21, T8N, R52W, 100N, 120E	Alluvium	106	Domestic
S21	1497-R	SE, NE, Sect. 21, T8N, R52W	Alluvium	110	Irrigation
S21	81878	SE, NE, Sect. 21, T8N, R52W	Alluvium	--	Stock

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S21	81878	SE, NE, Sect. 21, T8N, R52W, 2440N, 1300E	Alluvium	65	Stock
S22	10128	NW, NE, Sect. 22, T8N, R52W	Alluvium	50	Stock
S22	10129	NW, NE, Sect. 22, T8N, R52W	Alluvium	45	Stock
S22	111647	NE, NW, Sect. 22, T8N, R52W, 200N, 1500W	Ogallala	--	Domestic
S22	111647	NE, NW, Sect. 22, T8N, R52W, 200N, 1510W	Alluvium	50	Domestic
S22	111647	NE, NW, Sect. 22, T8N, R52W, 200N, 1500W	Alluvium	70	Domestic
S22	168703	NW, NW, Sect. 22, T8N, R52W, 1250N, 250W	Alluvium	99	Domestic, Stock
S22	168703	NW, NW, Sect. 22, T8N, R52W, 1270N, 250W	Alluvium	50	Domestic, Stock
S22	26428	SE, NW, Sect. 22, T8N, R52W	Alluvium	50	Dewatering
S22	26379	SE, NW, Sect. 22, T8N, R52W	Alluvium	60	Dewatering
S22	60535-F	SW, NW, Sect. 22, T8N, R52W, 1600N, 1300W	Alluvium	--	Recharge
S22	38239-MH	SE, SE, Sect. 22, T8N, R52W	Alluvium	--	Other
S22	3141-F	NE, SE, Sect. 22, T8N, R52W, 5300N, 1704W	Alluvium	74	Irrigation
S23	166-WCB	Sect. 23, T8N, R52W	Alluvium	60	--
S23	103103	NE, SW, Sect. 23, T8N, R52W, 2444S, 1986W	Ogallala	65	Domestic
S23	103103	NE, SW, Sect. 23, T8N, R52W	Alluvium	--	Domestic
S23	143413	NE, SW, Sect. 23, T8N, R52W	Alluvium	--	Domestic
S23	38241-MH	NW, SW, Sect. 23, T8N, R52W	Alluvium	--	Monitoring
S23	206620	SE, SW, Sect. 23, T8N, R52W, 1033S, 3670E	Alluvium	78	Domestic, Stock
S23	174955	SE, SW, Sect. 23, T8N, R52W, 1233S, 3490E	Alluvium	40	Stock
S23	38240-MH	SW, SW, Sect. 23, T8N, R52W	Alluvium	--	Monitoring
S23	108307	SW, SW, Sect. 23, T8N, R52W	Alluvium	--	Stock
S23	38266	SW, SW, Sect. 23, T8N, R52W	Alluvium	57	Domestic
S24	120023	NE, NE, Sect. 24, T8N, R52W, 306N, 684E	Alluvium	134	OTHER
S24	124602	NE, NE, Sect. 24, T8N, R52W, 1066N, 209E	Alluvium	63	OTHER
S24	120030	NE, NW, Sect. 24, T8N, R52W, 391N, 2046E	Alluvium	93	OTHER
S24	124603	NE, SE, Sect. 24, T8N, R52W, 1636N, 1271E	Alluvium	135	OTHER
S24	124596	NW, SE, Sect. 24, T8N, R52W, 1767N, 2765E	Alluvium	104	OTHER
S24	215747	SW, NE, Sect. 24, T8N, R52W, 2100S, 2300W	Alluvium	130	COMMERCIAL
S25	13473	NW, SW, Sect. 25, T8N, R52W	Alluvium	30	DOMESTIC
S25	14495	SE, NE, Sect. 25, T8N, R52W	Alluvium	200	DOMESTIC
S26	13690-F	NE, NW, Sect. 26, T8N, R52W	Alluvium	78	Commercial

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S26	13691-F	SW, NW, Sect. 26, T8N, R52W	Alluvium	72	Commercial
S26	138274	NW, NW, Sect. 26, T8N, R52W, 500N, 500W	Alluvium	50	Domestic, Stock
S26	237185	NW, NW, Sect. 26, T8N, R52W, 500N, 500W	Alluvium	50	Domestic, Stock
S27	38238	NE, NE, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	237209	SE, NE, Sect. 27, T8N, R52W, 2020N, 70W	Alluvium	38	Domestic, Stock
S27	174956	SE, NE, Sect. 27, T8N, R52W, 2435N, 135W	Alluvium	40	Stock
S27	236200	SE, NE, Sect. 27, T8N, R52W, 1471N, 1297W	Alluvium	60	Domestic, Stock
S27	249717	SW, NE, Sect. 27, T8N, R52W, 2042N, 2017W	Alluvium	80	Household Use Only
S27	16049	SW, NE, Sect. 27, T8N, R52W	Alluvium	72	Domestic
S27	44131	NE, NW, Sect. 27, T8N, R52W	Alluvium	75	Domestic, Stock
S27	44347	SE, NW, Sect. 27, T8N, R52W	Alluvium	75	Stock
S27	38237-MH	SE, NW, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	8460-R	NE, SE, Sect. 27, T8N, R52W, 1759S, 713E	Alluvium	104	Municipal
S27	8460-R	NE, SE, Sect. 27, T8N, R52W	Alluvium	95	Municipal
S27	8463-R	NE, SE, Sect. 27, T8N, R52W, 2007S, 397E	Alluvium	86	Municipal
S27	8465-R	NE, SE, Sect. 27, T8N, R52W, 2007S, 397E	Alluvium	86	Municipal
S27	8463-R	NE, SE, Sect. 27, T8N, R52W, 2007S, 397E	Alluvium	91	Municipal
S27	44452-MH	NE, SE, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	5505-F	NE, SE, Sect. 27, T8N, R52W	Alluvium	60	Irrigation
S27	8461-R	SE, SE, Sect. 27, T8N, R52W, 788S, 771E	Alluvium	--	Municipal
S27	8461-R	SE, SE, Sect. 27, T8N, R52W	Alluvium	110	Municipal
S27	22252	SE, SE, Sect. 27, T8N, R52W	Alluvium	43	Stock
S27	5506-F	SE, SE, Sect. 27, T8N, R52W	Alluvium	60	Irrigation
S27	8462-F	SW, SE, Sect. 27, T8N, R52W, 288S, 1475E	Alluvium	88	Municipal, Augmented
S27	8462-F	SW, SE, Sect. 27, T8N, R52W	Alluvium	87	Municipal, Augmented
S27	25200	NE, SW, Sect. 27, T8N, R52W, 1574S, 1539W	Alluvium	76	Domestic
S27	61062-F	NE, SW, Sect. 27, T8N, R52W, 1574S, 1470W	Alluvium	81	Industrial, Municipal
S27	38236-MH	NE, SW, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	23909	NE, SW, Sect. 27, T8N, R52W	Alluvium	60	Domestic
S27	25588-F	NE, SW, Sect. 27, T8N, R52W, 2100S, 1900W	Alluvium	--	Other
S27	25589-F	NE, SW, Sect. 27, T8N, R52W	Alluvium	--	Other
S27	43668-MH	NE, SW, Sect. 27, T8N, R52W	Alluvium	--	Monitoring

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S27	17-AD	NW, SW, Sect. 27, T8N, R52W	Alluvium	--	Irrigation
S27	25200	NW, SW, Sect. 27, T8N, R52W	Alluvium	40	Domestic
S27	61061-F	NW, SW, Sect. 27, T8N, R52W, 2520S, 800W	Alluvium	81	Industrial, Municipal
S27	43669-MH	NW, SW, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	38153-MH	NW, SW, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	54321-F	NW, SW, Sect. 27, T8N, R52W, 2100S, 700W	Alluvium	0	Irrigation
S27	--	SE, SW, Sect. 27, T8N, R52W, 230S, 1890W	Alluvium	--	Industrial, Municipal
S27	18104-F	SE, SW, Sect. 27, T8N, R52W, 230S, 1890W	Alluvium	58	Irrigation
S27	133037	SE, SW, Sect. 27, T8N, R52W, 840S, 1820W	Alluvium	70	Commercial
S27	86118	SE, SW, Sect. 27, T8N, R52W, 700S, 2010W	Alluvium	50	Domestic
S27	16498-F	SE, SW, Sect. 27, T8N, R52W, 230S, 1890W	Alluvium	--	Irrigation
S27	26960-MH	SE, SW, Sect. 27, T8N, R52W	Alluvium	--	Monitoring
S27	--	SE, SW, Sect. 27, T8N, R52W	Alluvium	--	Commercial
S27	46195-F	SE, SW, Sect. 27, T8N, R52W, 880S, 1770W	Alluvium	--	Municipal
S27	13645-F	SW, SW, Sect. 27, T8N, R52W	Alluvium	25	Industrial
S27	13646-F	SW, SW, Sect. 27, T8N, R52W	Alluvium	25	Industrial
S27	13647-F	SW, SW, Sect. 27, T8N, R52W	Alluvium	50	Industrial
S27	13648-F	SW, SW, Sect. 27, T8N, R52W	Alluvium	50	Industrial
S27	13649-F	SW, SW, Sect. 27, T8N, R52W	Alluvium	50	Industrial
S27	13650-F	SW, SW, Sect. 27, T8N, R52W	Alluvium	40	Industrial
S28	62618-F	SE, NE, Sect. 28, T8N, R52W	Alluvium	59	Other
S28	13651-F	SE, SE, Sect. 28, T8N, R52W	Alluvium	40	Industrial
S28	13644-F	SE, SE, Sect. 28, T8N, R52W	Alluvium	40	Industrial
S28	59850-F	SE, SE, Sect. 28, T8N, R52W, 400S, 1175E	Alluvium	--	Industrial, Commercial
S28	13651-F-R	SE, SE, Sect. 28, T8N, R52W, 400S, 1175E	Alluvium	77	Industrial, Commercial
S33	66811	Sect. 33, T8N, R52W	Alluvium	--	OTHER, GRAVEL PIT
S33	72469	Sect. 33, T8N, R52W, 1230N, 170W	Alluvium	--	DOMESTIC
S33	32731	NE, NE, Sect. 33, T8N, R52W	Alluvium	25	OTHER, MONITORING WELL
S33	31978	NE, NE, Sect. 33, T8N, R52W	Alluvium	--	OTHER, MONITORING WELL
S33	13023	NE, NW, Sect. 33, T8N, R52W	Alluvium	72	STOCK
S33	13022	NE, NW, Sect. 33, T8N, R52W, 995N, 1725E	Alluvium	72	STOCK
S33	1597	NE, NW, Sect. 33, T8N, R52W	Alluvium	--	COMMERCIAL

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S33	38155	NE, SE, Sect. 33, T8N, R52W	Alluvium	--	OTHER
S33	39918	NE, SE, Sect. 33, T8N, R52W	Alluvium	--	OTHER
S33	33037	NE, SE, Sect. 33, T8N, R52W	Alluvium	--	OTHER
S33	54322	NE, SE, Sect. 33, T8N, R52W, 2625N, 300E	Alluvium	0	IRRIGATION, OTHER
S33	34893	NE, SE, Sect. 33, T8N, R52W	Alluvium	--	OTHER, MONITORING WELL
S33	228944	NE, SW, Sect. 33, T8N, R52W, 2114N, 2483E	Alluvium	0	STOCK
S33	11801	NE, SW, Sect. 33, T8N, R52W	Alluvium	80	IRRIGATION
S33	207862	NW, NE, Sect. 33, T8N, R52W, 1225N, 1375W	Alluvium	--	OTHER, MONITORING WELL
S33	49841	NW, NE, Sect. 33, T8N, R52W, 1200N, 1400W	Alluvium	--	OTHER
S33	207865	NW, NE, Sect. 33, T8N, R52W, 1350N, 1500W	Alluvium	--	OTHER, MONITORING WELL
S33	207864	NW, NE, Sect. 33, T8N, R52W, 1350N, 1425W	Alluvium	--	OTHER, MONITORING WELL
S33	2207	NW, NE, Sect. 33, T8N, R52W, 1056N, 1795W	Alluvium	80	MUNICIPAL
S33	19970	NW, NE, Sect. 33, T8N, R52W	Alluvium	14	OTHER, MONITORING WELL
S33	12945	NW, NE, Sect. 33, T8N, R52W	Alluvium	75	STOCK
S33	39451	NW, NE, Sect. 33, T8N, R52W	Alluvium	75	STOCK
S33	207861	NW, NE, Sect. 33, T8N, R52W, 1275N, 1450W	Alluvium	--	OTHER, MONITORING WELL
S33	207870	NW, NE, Sect. 33, T8N, R52W, 1050N, 1400W	Alluvium	--	OTHER, MONITORING WELL
S33	207860	NW, NE, Sect. 33, T8N, R52W, 975N, 1400W	Alluvium	--	OTHER, MONITORING WELL
S33	22192	NW, NE, Sect. 33, T8N, R52W, 628N, 2429W	Alluvium	--	COMMERCIAL
S33	207868	NW, NE, Sect. 33, T8N, R52W, 1450N, 1350W	Alluvium	--	OTHER, MONITORING WELL
S33	207866	NW, NE, Sect. 33, T8N, R52W, 1275N, 1500W	Alluvium	--	OTHER, MONITORING WELL
S33	12947	NW, NE, Sect. 33, T8N, R52W	Alluvium	79	STOCK
S33	207937	NW, NE, Sect. 33, T8N, R52W, 1200N, 1500W	Alluvium	--	OTHER, MONITORING WELL
S33	207867	NW, NE, Sect. 33, T8N, R52W, 1200N, 1450W	Alluvium	--	OTHER, MONITORING WELL
S33	12946	NW, NE, Sect. 33, T8N, R52W	Alluvium	76	STOCK
S33	27652	NW, NW, Sect. 33, T8N, R52W	Alluvium	88	DOMESTIC
S33	36621	NW, NW, Sect. 33, T8N, R52W	Alluvium	14	OTHER, MONITORING WELL
S33	30766	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	48222	NW, NW, Sect. 33, T8N, R52W	Alluvium	52	DOMESTIC
S33	31749	NW, NW, Sect. 33, T8N, R52W	Alluvium	--	OTHER
S33	30767	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	30765	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S33	30764-M	NW, NW, Sect. 33 T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	207869	NW, NW, Sect. 33, T8N, R52W, 1200N, 1300W	Alluvium	--	OTHER, MONITORING WELL
S33	30770-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	22	OTHER, MONITORING WELL
S33	30761-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	30769-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	30771-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	30768-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	30760-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	30763-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	15	OTHER, MONITORING WELL
S33	207863	NW, NW, Sect. 33, T8N, R52W, 1050N, 1300W	Alluvium	--	OTHER, MONITORING WELL
S33	30762-M	NW, NW, Sect. 33, T8N, R52W	Alluvium	--	OTHER, MONITORING WELL
S33	20407	NW, SE, Sect. 33, T8N, R52W	Alluvium	74	STOCK
S33	5868-R	NW, SW, Sect. 33, T8N, R52W, 2616N, 68W	Alluvium	83	IRRIGATION
S33	5868-RR	NW, SW, Sect. 33, T8N, R52W, 2616N, 68W	Alluvium	109	IRRIGATION
S33	--	SE, NE, Sect. 33, T8N, R52W	Alluvium	--	DOMESTIC
S33	11693	SE, NE, Sect. 33, T8N, R52W	Alluvium	30	DOMESTIC, STOCK
S33	38156-MH	SE, NE, Sect. 33, T8N, R52W	Alluvium	--	OTHER, MONITORING WELL
S33	22022	SE, NE, Sect. 33, T8N, R52W	Alluvium	34	DOMESTIC
S33	23166	SE, SE, Sect. 33, T8N, R52W	Alluvium	77	STOCK
S33	3341-F	SE, SE, Sect. 33, T8N, R52W	Alluvium	45	IRRIGATION
S33	10073	SE, SE, Sect. 33, T8N, R52W	Alluvium	154	DOMESTIC
S33	7219-RR	SE, SE, Sect. 33, T8N, R52W	Alluvium	--	IRRIGATION
S33	82266	SE, SW, Sect. 33, T8N, R52W, 1S, 1443E	Alluvium	--	DOMESTIC, STOCK
S33	49750	SW, NE, Sect. 33, T8N, R52W	Alluvium	110	STOCK
S34	20433-MH	NE, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	32955-MH	NE, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	8464-R	NW, NE, Sect. 34, T8N, R52W	Alluvium	--	Municipal
S34	8464-R	NW, NE, Sect. 34, T8N, R52W	Alluvium	114	Municipal
S34	8464-R	NW, NE, Sect. 34, T8N, R52W	Alluvium	--	Municipal
S34	8463-R	NW, NE, Sect. 34, T8N, R52W	Alluvium	91	Municipal
S34	13381-F	SE, NE, Sect. 34, T8N, R52W	Alluvium	97	Commercial
S34	8465-R	SE, NE, Sect. 34, T8N, R52W	Alluvium	78	Municipal

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S34	918-AD	SE, NE, Sect. 34, T8N, R52W	Alluvium	--	Commercial
S34	45614	SW, NE, Sect. 34, T8N, R52W, 2285N, 1955E	Alluvium	98	Domestic
S34	12733-F	NW, SE, Sect. 34, T8N, R52W, 2340S, 1777E	Alluvium	100	Commercial
S34	8467-R	NW, SW, Sect. 34, T8N, R52W	Alluvium	65	Municipal
S34	--	NW, SW, Sect. 34, T8N, R52W, 1385S, 620W	Alluvium	--	Industrial, Municipal
S34	69547	NW, SW, Sect. 34, T8N, R52W, 1758S, 378W	Alluvium	60	Domestic
S34	20435-MH	NW, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	39545-MH	NE, NW, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	5494-F	NE, NW, Sect. 34, T8N, R52W, 1028N, 1553W	Alluvium	75	Municipal
S34	--	NE, NW, Sect. 34, T8N, R52W, 1029N, 1553W	Alluvium	--	Industrial, Municipal
S34	220875	NW, NW, Sect. 34, T8N, R52W, 412N, 4078E	Alluvium	35	Monitoring
S34	220876	NW, NW, Sect. 34, T8N, R52W, 344N, 4107E	Alluvium	33	Monitoring
S34	220874	NW, NW, Sect. 34, T8N, R52W, 356N, 4066E	Alluvium	35	Monitoring
S34	220873	NW, NW, Sect. 34, T8N, R52W, 380N, 3986E	Alluvium	35	Monitoring
S34	39771-MH	NW, NW, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	54319-F	NW, NW, Sect. 34, T8N, R52W, 725N, 750W	Alluvium	--	Irrigation
S34	54320-F	NW, NW, Sect. 34, T8N, R52W, 375N, 900W	Alluvium	--	Irrigation
S34	5504-F	NW, NW, Sect. 34, T8N, R52W	Alluvium	62	Irrigation
S34	38154-MH	NW, NW, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	39772-MH	SW, NW, Sect. 34, T8N, R52W	Alluvium	--	Monitoring
S34	46827-F	SW, NW, Sect. 34, T8N, R52W	Alluvium	--	Gravel Pit
S34	47581-F	SW, NW, Sect. 34, T8N, R52W	Alluvium	--	Gravel Pit
S35	44040	NW, NW, Sect. 35, T8N, R52W, 600N, 600W	Alluvium	85	Domestic
S35	45929	NW, NW, Sect. 35, T8N, R52W	Alluvium	78	Domestic
S35	20539-F	NW, NW, Sect. 35, T8N, R52W, 650N, 1300W	Alluvium	130	Commercial, Augmentation
S35	20540-F	NW, NW, Sect. 35, T8N, R52W, 650N, 1290W	Alluvium	130	Commercial
S35	20539-F	NW, NW, Sect. 35, T8N, R52W, 650N, 1230W	Alluvium	122	Commercial, Augmentation
S35	20540-F	NW, NW, Sect. 35, T8N, R52W, 1250N, 1150W	Alluvium	660	Commercial, Augmentation
S35	20540-F	NW, NW, Sect. 35, T8N, R52W, 650N, 1280W	Alluvium	132	Commercial
S35	17248-F	NW, NW, Sect. 35, T8N, R52W, 650N, 1300W	Alluvium	130	Commercial
S35	16968-F	NW, NW, Sect. 35, T8N, R52W	Alluvium	--	Commercial
S35	271198	NW, NW, Sect. 35, T8N, R52W, 1250N, 1150W	Alluvium	660	Monitoring

Section	Permit Number	Location	Aquifer	Well Depth (ft)	Use
S35	105538	NW, SW, Sect. 35, T8N, R52W, 1400S, 800W	Alluvium	300	Commercial
S35	45929	SW, NW, Sect. 35, T8N, R52W, 1330N, 140W	Alluvium	91	Domestic
S35	96388-VE	SW, NW, Sect. 35, T8N, R52W, 1330N, 140W	Alluvium	--	Domestic

OIL AND GAS WELLS

The locations for the Class I Injection wells, and all known oil and gas wells within the Area of Review are shown in the map below. The Injection wells are shown by markers 1 and 2, the oil and gas wells are shown as markers with letters A through L. The oil and gas wells existing within the AOR range in depth between 4430 ft and 4509 ft. below ground level. None of these wells penetrates the primary confining zone, therefore these oil and gas wells are not expected to act as conduits for injected fluids to contaminate USDWs.

Oil and Gas Wells in the Area of Review



The following table lists the existing oil and gas wells in the Area of Review ("AOR") and shows the well name, location, well type, and total depth, status, and the letter code that can be used to locate the well on the map, above.

Nearby Oil and Gas Wells						
API No.	Map Code	Location	TD (ft.)	Formation	Well Type	Status
507508986	A	S23, 8N, 52W, 1980 FNL, 1980 FWL	4,449	J Sands	Oil	P&A
507508030	B	S24, 8N, 52W, 1980 FSL, 660 FWL	4,610	J Sands	Oil	P&A
507508223	C	S27, 8N, 52W, 220 FSL, 1790 FWL	4,475	J Sands	Oil/Gas	P&A
507508206	D	S27, 8N, 52W, 1980 FNL, 1980 FEL	4,430	J Sands	Gas	P&A
507508105	E	S27, 8N, 52W, 2010 FNL, 1980 FWL	4,440	J Sands	Oil/Gas	P&A
507508185	F	S27, 8N, 52W, 220 FSL, 850 FWL	4,485	J Sands	Oil	P&A
507508210	G	S33, 8N, 52W, 1780 FSL, 470 FEL	4,476	J Sands	Oil/Gas	P&A
507505602	H	S33, 8N, 52W, 660 FNL, 660 FEL	4,509	J Sands	Gas	P&A
507508087	I	S34, 8N, 52W, 790 FNL, 705 FWL	4,483	J Sands	Oil	P&A
507508182	J	S34, 8N, 52W, 2010 FSL, 630 FWL	4,452	J Sands	Oil	P&A
507508145	K	S34, 8N, 52W, 1820 FNL, 1020 FWL	4,479	J Sands	Oil	P&A
507508146	L	S34, 8N, 52W, 665 FNL, 1980 FWL	4,480	J Sands	Gas	P&A

None of these deeper oil and gas wells penetrates the Morrison formation (the primary confining zone), making it unlikely that these wells could act as a conduit for injected fluid to contaminate USDWs. As long as the injection wells demonstrate adequate casing and cement through the Morrison formation, these wells should pose no threat to USDW contamination as a result of the injection activities from the Sterling wells.

Corrective Action Plan

For wells in the AOR that are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

There are no wells within the AOR which penetrate the primary confining zone (Morrison), therefore no corrective action will be required by the permit.

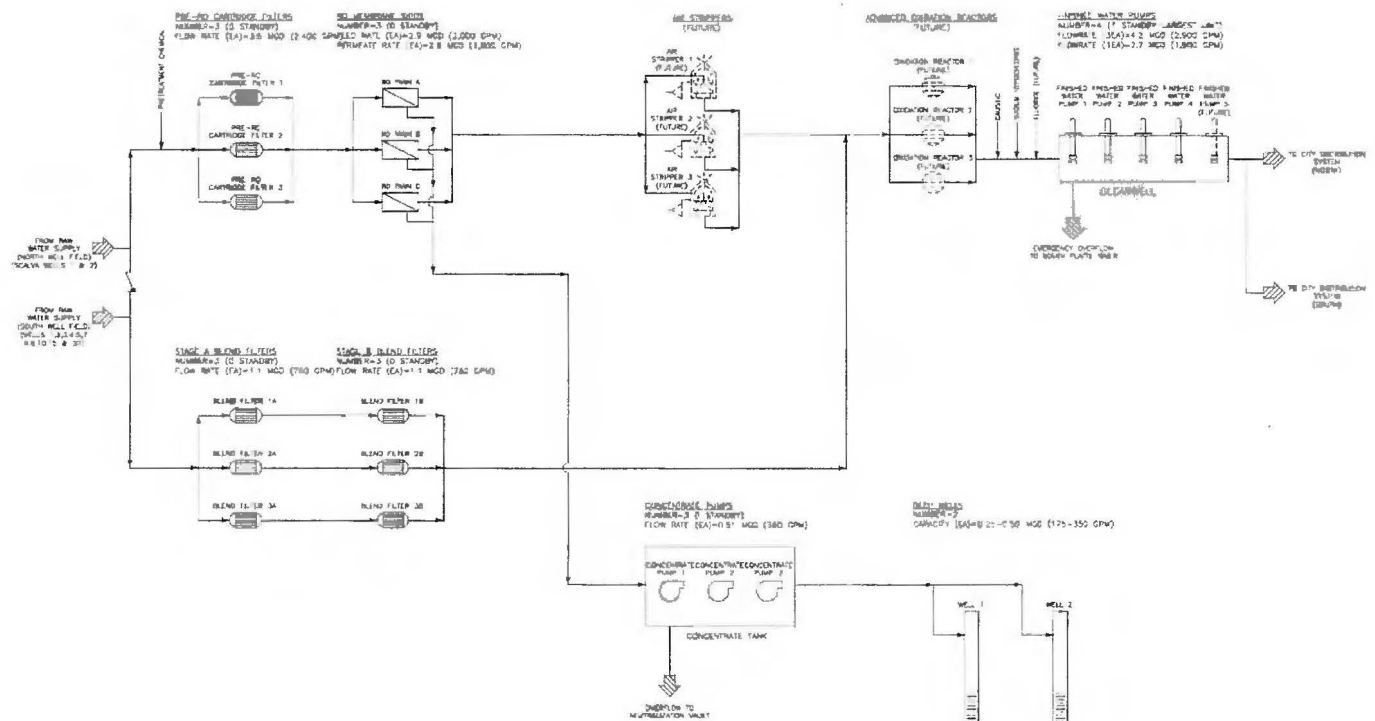
PART V. Well Operation Requirements (40 CFR 146.23)

Approved Injection Fluid

Injection fluid is limited to the concentrated brine generated from the reverse osmosis treatment of raw well water from the city's water treatment plant located near the site of the Sterling Deep Injection Well #1. This fluid may be injected into the deep disposal

wells only after sample analysis proves that it meets EPA standards for non-hazardous municipal disposal.

This treatment plant will receive raw water from the City's water production wells and removes contaminants through a reverse osmosis (RO) process. Approximately 80-90% of the raw water emerges from the RO units as product water for distribution to city residents. The remaining 10-20% of the water from the RO units emerges as concentrated brine that will be disposed deep underground via Sterling's Deep Disposal Wells No. 1 and No. 2. This waste water is required to meet EPA standards for non-hazardous municipal fluids prior to disposal. See the water treatment process, below:



In addition to the concentrated brines from the RO units, additional waste fluids may be generated as a result of periodic cleaning of the RO units. As salts concentrate on the high pressure side of the membrane, the very small pores of the membrane may become plugged. Organic compounds can also plug the pores. As a result of this plugging, the flow decreases and the membrane must be cleaned. To maintain efficiency of the RO units, a volume of water is circulated on the high pressure side of the system with a cleaning agent (for hardness or organic plugging) until the membrane is flushed clean.

Prior to introducing this flush fluid to the RO units, it is expected to fall within a pH range of 2.5 to 12. After it is removed from the RO units, this flush fluid will be neutralized prior to disposal. This fluid may be injected into the deep disposal wells only after sample analysis proves that it meets EPA standards for non-hazardous municipal disposal fluids (see the permit, APPENDIX D).

As part of the permit application, the applicant has submitted the projected water quality information for the concentrated brine intended for injection. This analysis information is shown in the following table:

Projected Water Quality (90% Nanofiltration Recovery)

Parameter	Units	Raw Value ⁽¹⁾	Concentrate Value ⁽²⁾	Concentration Factor	Percent Removal ⁽³⁾	Permeate Value
Alkalinity	(mg/L as CaCO ₃)	247	2,267	9	91%	22
Aluminum	(µg/L)	undetected	undetected	-	-	undetected
Ammonium	(mg/L)	undetected	undetected	-	-	undetected
Antimony	(µg/L)	undetected	undetected	-	-	undetected
Arsenic	(µg/L)	5	50	10	100%	0
Barium	(µg/L)	60	600	10	100%	0
Beryllium	(µg/L)	undetected	undetected	-	-	undetected
Bicarbonate	(mg/L)	301	2,766	9	-	27
Boron	(mg/L)	0.291	2.91	10	100%	0
Bromide	(µg/L)	624	4,331	7	66%	212
Cadmium	(µg/L)	undetected	undetected	-	-	undetected
Calcium	(mg/L)	191	1,807	9	94%	11
Chloride	(mg/L)	97	752	8	75%	24
Chromium	(µg/L)	undetected	undetected	-	-	undetected
Copper	(µg/L)	undetected	42	-	-	undetected
Fluoride	(mg/L)	0.89	8.9	10	100%	0
Hardness	(mg/L as CaCO ₃)	719	6,827	9	94%	41
Iron Dissolved	(µg/L)	undetected	418	-	-	undetected
Lead	(µg/L)	2.3	9.3	4.1	34%	1.5
Manganese	(µg/L)	462	4,620	10	100%	0
Magnesium	(mg/L)	59	563	10	95%	3.0
Mercury	(µg/L)	undetected	undetected	-	-	undetected
Nickel	(µg/L)	undetected	26	-	-	undetected
Nitrate as N	(mg/L)	4.06	13.6	3	26%	3.00
Nitrite as N	(mg/L)	undetected	undetected	-	-	undetected
Ortho-P as P	(mg/L)	undetected	1	-	-	undetected
pH	(SU)	7.4	7.7	-	-	6.8
Potassium	(mg/L)	16	133	8	81%	3.0
Selenium	(µg/L)	4.0	40	10	100%	0
Silver	(µg/L)	undetected	undetected	-	-	undetected
Sodium	(mg/L)	182	1,509	8	81%	34.6
Strontium	(mg/L)	1.5	15	10	100%	0
Sulfate	(mg/L)	755	7,210	10	95%	37.8
Sulfide	(mg/L)	undetected	undetected	-	-	undetected
Silica	(mg/L)	28	247	9	87%	3.6
Thallium	(µg/L)	undetected	undetected	-	-	undetected
TDS	(mg/L)	1,632	14,704	9	89%	180
TOC	(mg/L)	3.1	31	10	100%	0
Total Iron	(µg/L)	1,094	10,940	10	100%	0
TP as P	(mg/L)	undetected	1	-	-	undetected
Uranium ⁽⁴⁾	(µg/L)	40	382	10	95%	2.0
Gross Alpha ^{(5) (6)}	(pCi/L)	29	277	10	95%	1.5
Gross Beta ⁽⁶⁾	(pCi/L)	18	172	10	95%	0.9
Radium 226 ⁽⁶⁾	(pCi/L)	0.4	4	10	95%	0.02
Radium 228 ⁽⁶⁾	(pCi/L)	0.5	5	10	95%	0.03

⁽¹⁾ Raw values based on blended raw water quality during peak demands (40% Site 1 Wells and 60% Scalva Wells).

⁽²⁾ Concentrate values based on 90% recovery nanofiltration system.

⁽³⁾ Percent removal values based on pilot testing. Percent removal for gross alpha, gross beta, radium 226 and radium 228 estimated to be similar to removal of uranium.

⁽⁴⁾ 550 µg/L of naturally occurring uranium = 372 pCi/L

⁽⁵⁾ Gross alpha includes total alpha particle activity. Raw value based on average from 2004 - 2008.

⁽⁶⁾ Raw values for gross alpha, gross beta, radium 226 and radium 228 based on average from 2004 - 2008 sampling.

This projected water quality information shows the fluid to be non-hazardous; however, the uranium levels are higher than levels that would allow the fluid to be injected above the lowermost USDW. For this reason, injection will only be approved into a geologic formation that exists below the base of all USDWs.

These Class I injection wells are NOT approved for disposal or injection of hazardous waste as defined by CFR 40 Part 261.

Injection Pressure Limitation (40 CFR 146.13(a)(1))

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the injection zone. The initial fracture gradient for the injection formations is set initially at 0.733 psi/ft. During well completion, the actual fracture gradients for each injection zone will be determined and the Maximum Allowable Injection Pressure (MAIP) will be established at a pressure that will not cause fracturing or extension of fractures within any injection zone.

Initially, the MAIP is calculated according to the following formula:

$$\text{MAIP} = [\text{fg} - (0.433 * \text{sg})] * \text{d}$$

MAIP = Maximum Allowable Injection Pressure (measured at surface)

fg = fracture gradient (psi/ft) (determined from submitted data or tests)

sg = specific gravity (of injected fluid)

d = depth to top of injection zone (or top perforation)

In order to calculate the MAIP, the fg was estimated conservatively at .733 psi/ft. and as discussed above the sg was estimated at 1.04. The depth used to calculate the initial injection pressure is that of the top of the permitted injection formation at 5261 ft. which leads to the following result:

$$\begin{aligned}\text{MAIP} &= [0.733 - (0.433 * 1.04)] * 5261 \\ &= 1487 \text{ psi}\end{aligned}$$

The results of the Step-Rate test required in Part III of this document will be used to determine an accurate value for the injection zone fracture gradient (fg). This value will be used to recalculate the MAIP according to the formula shown above.

The applicant has provided information that estimates the injection fluid specific gravity (sg) to be less than 1.04. The initial injection pressure will be established using that assumption, however in order to fulfill the requirement that the injection pressure not exceed the fracture pressure of the injection zone, the permit has a further requirement to reduce the MAIP if the sg exceeds 1.04 during the operation of the well.

MAXIMUM INJECTION PRESSURES				
Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Injected Fluid Specific Gravity	Initial MAIP (psi)
Paleozoic Formations	5261	0.733	1.04	1487

Injection Volume Limitation

There is no limitation on the number of barrels of fluid that shall be injected into this well, provided further that in no case shall injection pressure exceed the MAIP.

Mechanical Integrity (40 CFR 146.8 and GW Section Guidance #39)

An injection well has mechanical integrity if:

1. There is no significant leak in the casing, tubing, or packer (Part I); and
2. There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Well construction and site-specific conditions dictate the following requirements for Mechanical Integrity (MI) demonstrations:

Part I MI - Internal MI will be demonstrated prior to beginning injection. Since these wells are constructed with a standard casing, tubing, and packer configuration, a successful test is required by UIC GW Section Guidance 39 to take place at least once every five (5) years. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing, or packer.

Part II MI - External MI will be demonstrated prior to beginning injection operations. Class I injection well regulations require the use of a Temperature Log. Cement Bond or Cement Evaluation type logs will also be used to assess the quality and location of the cement. If the cement logs do not meet minimum requirements for cement quality and quantity, Part II MI will be evaluated with periodic Radioactive Tracer Surveys.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

MONITORING:

Instantaneous injection and annulus pressures, injection rate, and cumulative injected volume must be observed and recorded continuously.

FLUID ANALYSIS:

Once monthly, the Permittee must analyze a sample of the injected fluid according to the list of analytes shown below. After the monthly analyses show that the injection fluid has stabilized, sampling will be made on a quarterly basis, the results of which will be submitted to EPA as part of the Quarterly Report to the Director according to the schedule shown in the section titled "REPORTING", below.

Parameter Analyzed	EPA Analytical Method
Total Dissolved Solids (mg/l)	
Total Suspended Solids (mg/l)	
Specific Conductivity (umhos/cm)	
pH	
Specific Gravity	
Corrosivity Index (Langelier Saturation Index)	
Nitrate-Nitrite (both as N) mg/l	
Sulfate (mg/l)	
Chloride (mg/l)	
Magnesium (mg/l)	
Sodium (mg/l)	
Calcium (mg/l)	
Iron (mg/l)	
Gross Alpha (pCi/l)	E900.0
Gross Beta (pCi/l)	E900.0
Strontium (mg/l)	272.1, 272.2, 200.7
Uranium-234 (pCi/l)	E907.0
Uranium-238 (pCi/l)	E907.0
Thorium-230 (pCi/l)	E907.0
Radium-226 (pCi/l)	E903.0
Radium-228 (pCi/l)	E904.0
Potassium-40 (pCi/l)	E901.1
Lead-210 (pCi/l)	E905.0 Mod.

REPORTING:

Monthly averages and monthly maximum and minimum values shall be tabulated for injection and annulus pressures, injection rate, and cumulative injected volume. This information is required to be reported quarterly, along with a listing of the sources of injected fluids, as part of the Quarterly Report to the Director.

SCHEDULE FOR QUARTERLY REPORTING:

	REPORTING PERIOD	REPORT DUE TO EPA
1 st Quarter	January 1 – March 31	May 15
2 nd Quarter	April 1 – June 30	August 15
3 rd Quarter	July 1 – September 30	November 15
4 th Quarter	October 1- December 31	February 15

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

The plugging and abandonment plan for this project has been designed to prevent the movement of fluids into or between USDWs. Cement plugs will be placed as follows to accomplish that goal:

- In order to isolate the injection zone, all injection perforations will be squeezed with cement, and a cement plug will be placed inside casing to a point 100 ft above the uppermost perforation.
- The lowermost USDW will be isolated from deeper non-USDWs by placing a bridge plug 50 ft below the base of USDWs and by setting a 100 ft cement plug on top of the bridge plug.
- The deeper USDWs will be isolated from the Alluvial aquifers by placing a bridge plug 50 ft below the top of the Niobrara Formation and by placing a 100 ft cement plug on top of the bridge plug.
- The base of the surface casing will be isolated by placing a bridge plug 50 ft below the base of surface casing by setting a 100 ft cement plug on top of the bridge plug.
- The Alluvial aquifers will be protected by placing a bridge plug 100 ft below the base of the Alluvial aquifers and by filling the casing with cement plug from the bridge plug to surface.
- Intervals not plugged with cement will be filled with 9.6 ppg mud or plugging gel.

The plugging plan can be seen in the schematic diagram on the following page.

PERMIT REVIEW WORKSHEET

WELL NAME Sterling Deep Injection #1 OPERATOR City of Sterling, Co
 S 27 T 8N R 53E Logan COUNTY, CO

CATEGORY : ☐ RA ☒ NEW CONSTRUCTION ☐ NEW CONVERSION from _____
 LOCATION : ☐ U/O ☐ WR ☐ SU ☐ UM ☐ MT-IND ☐ MT-NON IND
 WELL TYPE : ☐ EOR ☐ NON-COMMERCIAL SWD ☐ COMMERCIAL SWD x CLASS I

DEPTH*	GEOLOGY	SCHEMATIC	DETAILS	LOGS	TESTS	C/A	WELLHEAD EQUIP	OPERATION
0	0							
1	200		PLUG : 0-200'	<input type="checkbox"/> CBL/VDL/ γ -RAY	<input type="checkbox"/> PORE PRESSURE	<input type="checkbox"/> PRESSURE LIMIT	<input type="checkbox"/> GAUGES	<input type="checkbox"/> COMPLETION RPT
2	400		CIBP @ 200'	<input type="checkbox"/> OAL	<input type="checkbox"/> PERMEABILITY	<input type="checkbox"/> REMEDIAL CMT	<input type="checkbox"/> STAB GAUGES	<input type="checkbox"/> WORKOVER RPT
3	600		PLUG: 900-1100'	<input type="checkbox"/> CASING INSP	<input type="checkbox"/> IZ SAMPLE		<input type="checkbox"/> FLOWMETER	<input type="checkbox"/> AE
4	800		CIBP @ 1100'	<input type="checkbox"/> RTS	<input type="checkbox"/> SOURCE SAMPLE		<input type="checkbox"/> RATE INDICATOR	<input type="checkbox"/> Vmax
5	1000		9 5/8" to 1000'	<input type="checkbox"/> TEMP	<input type="checkbox"/> SRT		<input type="checkbox"/> SAMPLE TAP	<input type="checkbox"/> Pmax
6	1200		Cmt to Surface	<input type="checkbox"/> DIL	<input type="checkbox"/> MIT			<input type="checkbox"/> MON
7	1400			<input type="checkbox"/> γ -RAY				<input type="checkbox"/> RPT
8	1600			<input type="checkbox"/> RESISTIVITY				
9	1800			<input type="checkbox"/> CONDUCTIVITY				
10	2000			<input type="checkbox"/> SP				
11	2200			<input type="checkbox"/> SONIC (ϕ)				
12	2400			<input type="checkbox"/> N-DENSITY				
13	2600							
14	2800							
15	3000							
16	3200							
17	3400							
18	3600		PLUG : 3411-3511'					
19	3800		CIBP @ 3511'					
20	4000		DV tool @ 4000'					
21	4200							
22	4400							
23	4600							
24	4800							
25	5000		PLUG: 5000-5100'					
26	5200		CIBP @ 5100'					
27	5400							
28	5600							
29	5800							
30	6000							
31	6200		PLUG: All perfed					
32	6400		injection zones					
33	6600							
34	6800							
35	7000		7" to Pre Cambrian					
36			Cmt to surface					
37								
38								
39								
40								
41								
42								
43								
44								

* Depths shown are approximations based on surrounding wells
 Actual depths will be determined after logging.

PERMIT NUMBER CO12163-00000

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the Permittee to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

A Letter of Credit with a Standby Trust Fund.

Evidence of continuing financial responsibility is required to be submitted to the Director annually.



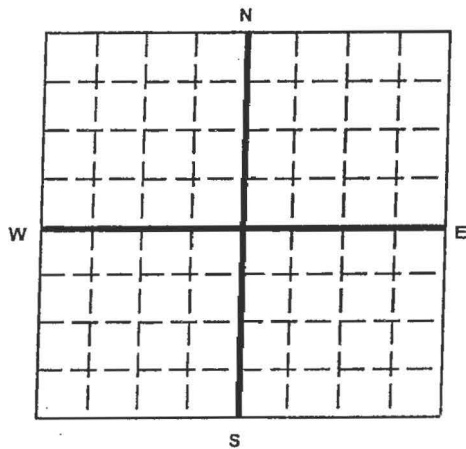
United States Environmental Protection Agency
Washington, DC 20460

Application To Transfer Permit

Name and Address of Existing Permittee

Name and Address of Surface Owner

Locate Well and Outline Unit on
Section Plat - 640 Acres



State

County

Permit Number

Surface Location Description

____ 1/4 of ____ 1/4 of ____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface

Location ____ ft. frm (N/S) ____ Line of quarter section
and ____ ft. from (E/W) ____ Line of quarter section.

Well Activity

Well Status

Type of Permit

____ Class I

____ Operating

____ Individual

____ Class II

____ Modification/Conversion

____ Area

____ Brine Disposal

____ Proposed

Number of Wells ____

____ Enhanced Recovery

____ Hydrocarbon Storage

____ Class III

____ Other

Lease Number

Well Number

Name(s) and Address(es) of New Owner(s)

Name and Address of New Operator

Attach to this application a written agreement between the existing and new permittee containing a specific date for transfer of permit responsibility, coverage, and liability between them.

The new permittee must show evidence of financial responsibility by the submission of a surety bond, or other adequate assurance, such as financial statements or other materials acceptable to the Director.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR

Name and Official Title (Please type or print)

Signature

Date Signed

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

**Locate Well and Outline Unit on
Section Plat - 640 Acres**

Well Number

S

[illegible]

EPA Form 7520-11



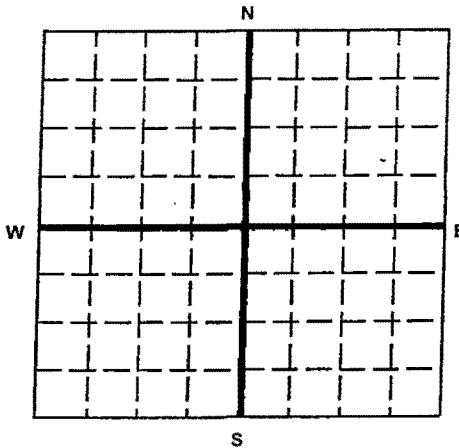
United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility

Name and Address of Owner/Operator

Locate Well and Outline Unit on
Section Plat - 640 Acres



State

County

Permit Number

Surface Location Description

____ 1/4 of ____ 1/4 of ____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface

Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section.

TYPE OF AUTHORIZATION

- ☐ Individual Permit
☐ Area Permit
☐ Rule

Number of Wells ____

Lease Name

WELL ACTIVITY

- ☐ CLASS I
☐ CLASS II
☐ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage
☐ CLASS III

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- ☐ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☐ Other

CEMENTING TO PLUG AND ABANDON DATA:

	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)							
Depth to Bottom of Tubing or Drill Pipe (ft)							
Sacks of Cement To Be Used (each plug)							
Slurry Volume To Be Pumped (cu. ft.)							
Calculated Top of Plug (ft.)							
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)							
Type Cement or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To

Estimated Cost to Plug Wells

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title (Please type or print)

Signature

Date Signed



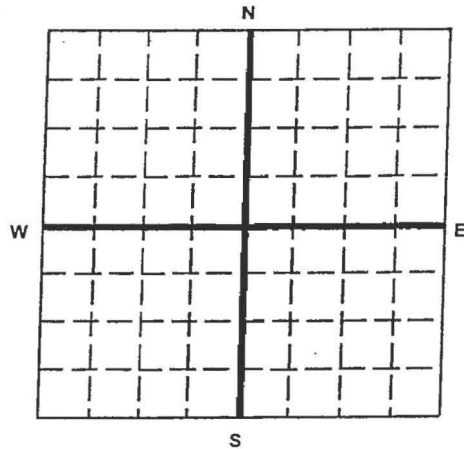
United States Environmental Protection Agency
Washington, DC 20460

WELL REWORK RECORD

Name and Address of Permittee

Name and Address of Contractor

Locate Well and Outline Unit on
Section Plat - 640 Acres



State

County

Permit Number

Surface Location Description

____ 1/4 of ____ 1/4 of ____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface

Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section.

WELL ACTIVITY

- ☐ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage

Lease Name

Total Depth Before Rework

Total Depth After Rework

Date Rework Commenced

Date Rework Completed

TYPE OF PERMIT

- ☐ Individual
☐ Area

Number of Wells ____

Well Number

WELL CASING RECORD -- BEFORE REWORK

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

WELL CASING RECORD -- AFTER REWORK (Indicate Additions and Changes Only)

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

DESCRIBE REWORK OPERATIONS IN DETAIL
USE ADDITIONAL SHEETS IF NECESSARY

WIRE LINE LOGS, LIST EACH TYPE

Log Types	Logged Intervals

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title (Please type or print)

Signature

Date Signed



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VIII

999 18th STREET - SUITE 300
DENVER, COLORADO 80202-2466

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 34
Cement bond logging techniques and interpretation

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

These procedures are to be followed when running and interpreting cement bond logs for injection and production (area of review) wells.

PART I - PREPARE THE WELL

Allow cement to cure for a sufficient time to develop full compressive strength. A safe bet is to let the cement cure for 72 hours. If you run the bond log before the cement achieves its maximum compressive strength, the log may show poor bonding. Check cement handbooks for curing times.

Circulate the hole with a fluid (either water or mud) of uniform consistency. Travel times are influenced by the type of fluid in the hole. If the fluid changes between two points, the travel times may "drift," causing difficulty in interpretation and quality control.

Be prepared to run the cement bond log under pressure to reduce the effects of micro-annulus. Micro-annulus may be caused by several reasons, but the existence of a micro-annulus does not necessarily destroy the cement's ability to form a hydraulic seal. If the log shows poor bonding, rerun the log with the slightly more pressure on the casing as was present when the cement cured. This will cause the casing to expand against the cement and close the micro-annulus.

PART II - PARAMETERS TO LOG

Amplitude (mV) - This curve shows how much acoustic signal reaches a receiver and is an important indicator of cement bond. Record the amplitude on the 3 foot spaced receiver.

Travel time (μ s) - This curve shows the amount of time it takes an acoustic signal to travel between the source and a receiver. For free pipe of a given size and weight, the travel time between points is very predictable, although



variable among different company's tools. Service companies should be able to provide accurate estimates of travel times for free pipe of a given size and weight. Travel time is required as a quality control measurement. Record the travel time on the 3 foot spaced receiver.

Variable density (VDL) - Pipe signals, formation signals, and fluid signals are usually easy to recognize on the VDL. If these signals can be identified, a practical determination for the presence or absence of cement can be made. VDL is logged on the 5 foot spaced receiver.

Casing collar locator (CCL) - Used to correlate the bond log with cased hole logs and to match casing collars with the collars that show up on the VDL portion of the display.

Gamma ray - Used to correlate the bond log with other logs.

PART III - LOGGING TECHNIQUE

Calibrate the tool in free pipe at the shop, prior to, and following the log run. Include calibration data with log.

Run receivers spaced 3 feet and 5 feet from transmitter.

Run at least 3 bow-type or rigid aluminum centralizers in vertical holes, 6 centralizers in directional holes. A CCL is not an adequate centralizer.

Complete log header with casing/cement data, tool/panel data, gate settings and tool sketch showing centralizers.

Set the amplitude gate so that skipping does not occur at amplitudes greater than 5 mV.

Record amplitude with fixed gate and note position on log.

Record amplified amplitude on a 5X scale for low amplitudes.

Record amplitude and travel time on the 3 foot receiver.

Record travel time on a 100 μ s scale (150 - 250, 200 - 300).

Logging speed should be approximately 30 ft/min.

Log repeat sections.



PART IV - QUALITY CONTROL

Compare the tool calibration data to see if the tool "drifts" during logging. Differences in the calibration data may require you to re-log the well to obtain reliable data.

Compare repeat sections to see if logging results are repeatable.

Check the logged free pipe travel times with the service company charts for the specific tool and casing size used. Since the travel times depend on such factors as casing weight, type of fluid in the hole, etc., these charts should be used only as guidelines. When you are confident of the free-pipe travel times as seen on the log, use them. When interpreting the log, a decrease in travel time (faster times) with simultaneous reduction of amplitude may show a de-centered tool. A 4 to 5 micro-second (μ s) decrease in travel time corresponds to about a 35% loss of amplitude. A decrease in travel time more than 4 to 5 μ s is unacceptable.

PART V - LOG INTERPRETATION

Do not rely on the service company charts for amplitudes corresponding to a good bond. These amplitudes depend on many factors: type of cement used, fluid in the hole, etc.

To estimate bond index, choose intervals on the log that correspond to 0% bond and 100% bond. Read the amplitude corresponding to 100% bond from the best-bonded interval on the log (NOTE: the accuracy of this amplitude reading is very critical to the bond index calculations). Next, find the amplitude corresponding to 0% bond. Some bond logs may not include a section with free pipe. In this instance, choose the appropriate free-pipe travel time from the service company charts for your specific tool, or from the generalized chart (TABLE 2) at the end of this guidance. To calculate a bond index of 80%, use the following equation:

$$A_{80} = 10^{[(0.2)\log(A_0) + (0.8)\log(A_{100})]}$$

where:

A_{80} = Amplitude at 80% bond (mV)
 A_0 = Amplitude at 0% bond (mV)



A_{100} = Amplitude at 100% bond (mV)

EXAMPLE:

As an example, consider a bond log showing the following conditions:

- Free pipe (0% bond) amplitude at 81 mV.
- 100 % bond amplitude at 1 mV.

Substituting the above values into the equation results in:

$$A_{80} = 10^{[(0.2)\log(81) + (0.8)\log(1)]}$$

$$A_{80} = 2.41mV$$

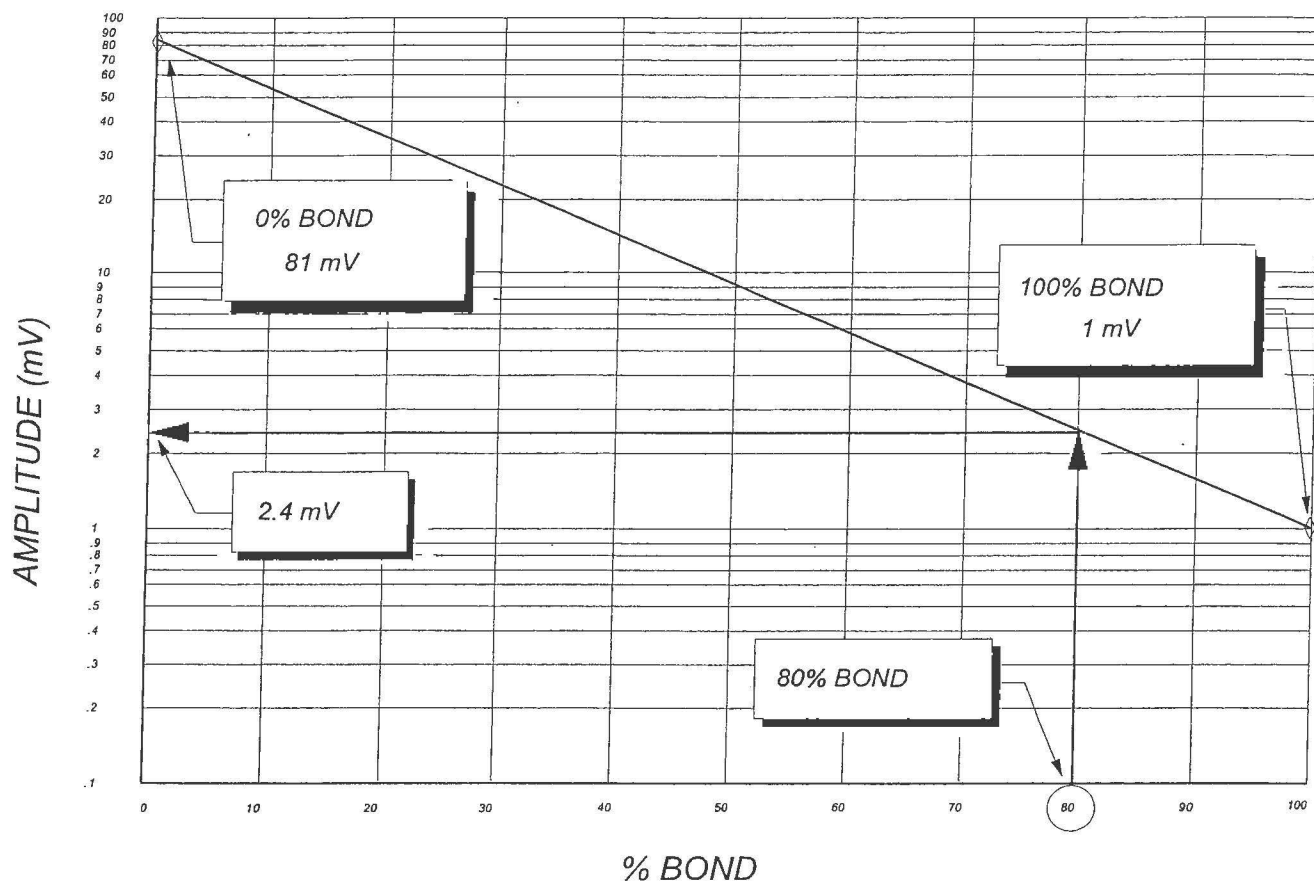
Another way to calculate the amplitude at 80% bond is by plotting these same log readings on a semi-log chart.

Plot the values for 0% Bond and 100% Bond vs. their respective Amplitudes on a semi-log chart - amplitudes on the log scale (y-axis), and bond indices on the linear scale (x-axis). Then, connect the points with a straight line.

To estimate the amplitude corresponding to an 80% Bond Index, enter the graph on the x-axis at 80% bond. Draw a straight line upward until you reach the diagonal line connecting the 0% and 100% points. Continue by drawing a horizontal line to the y-axis. This point on the y-axis is the amplitude corresponding to an 80% Bond Index.



Using the values from the example above, your chart will look like that shown below:



In this example, 80% bond shows an amplitude of 2.4 mV.

A convenient way to evaluate the log is to draw a line on the bond log's **amplified** amplitude (5X) track corresponding to the calculated 80% bond amplitude. Whenever the logged **amplified** amplitude (5X) curve drops below (to the left of) the drawn line, this indicates a bond of 80% or more.

PART IV - CONCLUSIONS - REMINDERS

Different pipe weights and cement types will affect the log readings, so be mindful of these factors in wells with varying pipe weights and staged cement or squeeze jobs.



Collars generally do not show up on the VDL track in well-bonded sections of casing.

Longer (slower) travel time due to cycle skipping or cycle stretch usually suggests good bonding.

Shorter (faster) travel times indicate a de-centered tool or a fast formation and will provide erroneous amplitude readings that make evaluation impossible through that section of the log. Fast formations do not assure that the cement contacts the formation all around the borehole.

Although the bond index is important, you should not base your assessment of the cement quality on that one factor alone. You should use the VDL to support any indication of bonding. Also, you must know how each portion of the CBL (VDL, travel time, amplitude, etc.) influences another.

Most 3'-5' CBL's cannot identify a 1/2" channel in cement. Therefore, you also need to consider the thickness of a cemented section needed to provide zone isolation. For adequate isolation in injection wells, the log should indicate a continuous 80% or greater bond through the following intervals as seen in TABLE 1, below:

TABLE 1 - INTERVALS FOR ADEQUATE BOND

PIPE DIAMETER (in)	CONTINUOUS INTERVAL WITH BOND \geq 80% (ft)
4-1/2	15
5	15
5-1/2	18
7	33
7-5/8	36
9-5/8	45
10-3/4	54

Adequately bonded cement by itself will not prevent fluid movement. If the bond log shows adequate bond through an interval where the geology allows fluid to move (permeable and/or fractured zones), fluids may move around perfectly bonded cement by travelling through the formation. Always cross-check your bond log with open hole logs to see that you have adequate bonding through the proper interval(s).



TABLE 2 - TRAVEL TIMES AND AMPLITUDES FOR FREE PIPE
(3 FT RECEIVER)

CASING SIZE (in)	CASING WEIGHT (lb/ft)	TRAVEL TIME (μ s)		AMPLITUDE (mV)
		1-11/16" TOOL	3-5/8" TOOL	
4-1/2	9.5	252	233	81
	11.6	250	232	81
	13.5	249	230	81
5	15.0	257	238	76
	18.0	255	236	76
	20.3	253	235	76
5-1/2	15.5	266	248	72
	17.0	265	247	72
	20.0	264	245	72
	23.0	262	243	72
7	23.0	291	271	62
	26.0	289	270	62
	29.0	288	268	62
	32.0	286	267	62
	35.0	284	265	62
	38.0	283	264	62
7-5/8	26.4	301	281	59
	29.7	299	280	59
	33.7	297	278	59
	39.0	295	276	59
9-5/8	40.0	333	313	51
	43.5	332	311	51
	47.0	330	310	51
	53.5	328	309	51
10-3/4	40.5	354	333	48
	45.5	352	332	48
	51.0	350	330	48
	55.5	349	328	48





UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VIII

999 18th STREET - SUITE 300
DENVER, COLORADO 80202-2466

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 35

Procedures to follow when excessive annular pressure is observed on a well.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

The following procedure is intended as an aid to UIC field inspectors when they encounter excessive annular pressure on a well. Excessive annular pressure is defined as 100 psi or 10% of the tubing pressure, whichever is less.

Usually, annular pressure is a direct indication of a loss of mechanical integrity. In some instances, recurring annular pressure may be caused by fluctuations in the temperature of the injected fluid. These temperature fluctuations may cause the annular pressure to increase when a hot fluid is being injected and decrease as the temperature of the injected fluid cools. The presence of temperature-induced pressure on the annulus does not indicate a malfunction in the casing/tubing/packer system and is not considered a loss of mechanical integrity. Wells exhibiting recurring temperature-induced annular pressure may be allowed to continue injecting if a temperature monitoring program is approved and followed.

This guidance was written to help determine the cause of annular pressure. When the procedures in this guidance are followed, any major mechanical integrity problems (a breach in the casing/tubing/packer system) will become apparent quickly. A quick determination will allow the operator to begin follow-up procedures immediately to prevent contamination to USDWs.

Use Section Guidance No. 35 to determine if the well has experienced a loss of mechanical integrity. If you find that there is a loss of mechanical integrity, use *Headquarters Guidance No. 76. - Follow-up to loss of Mechanical Integrity for Class II Wells* to bring the well back into compliance. The use of Section Guidance No. 35 is not to be confused with, nor does it supersede any provision of Headquarters Guidance No. 76. Instead, the two guidance documents are meant to work together to identify and to remedy any potential mechanical integrity failure.

A flowchart for Section Guidance No. 35 is included for quick reference in the field.



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PROCEDURES TO FOLLOW WHEN EXCESSIVE ANNULAR PRESSURE IS OBSERVED

During field inspections, the following procedures should be followed when excessive annular pressure is observed. Excessive annular pressure is defined as 100 psi or 10% of the tubing pressure, whichever is less.

<u>Note Conditions at the Well</u>	Note tubing and annular pressure readings, and the operating status of the well (injecting, shut-in, etc.) on the UIC inspection form.	
<u>See If Annulus Pressure Will Bleed-off</u>	Attempt to bleed the pressure from the annulus by having the operator open the annulus (for a maximum of sixty seconds). It is the operator's responsibility to collect and dispose of any fluids bled from the annulus.	
<u>Did the Annular Pressure Bleed to 0 Psi Within Sixty Seconds?</u>	<p><u>YES</u></p> <p>Have the operator close the annulus.</p> <p>On your inspection form note the volume of fluid (or gas) bled from the annulus during the sixty seconds, and the tubing and annulus pressures.</p>	<p><u>NO</u></p> <p>Have the operator close the annulus.</p> <p>On your inspection form note the volume of fluid (or gas) bled from the annulus during the sixty seconds, and the tubing and annulus pressures.</p> <p>Have the operator shut the well in for 2 hours, and if possible, bleed pressure from the injection tubing. Record the tubing and annulus pressure after two hours.</p> <p>Bleed off the annulus for 60 seconds. Record the tubing and annulus pressures after bleed-off, and estimate the volume bled off.</p> <p>INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.</p> <p>END PROCEDURE.</p>
<u>See If Pressure Returns Within 15 Minutes</u>	Continue to monitor the well for annulus pressure return for at least 15 minutes after the annulus valve is closed.	



<p><u>Does Pressure Return to the Annulus after 15 Minutes?</u></p>	<p><u>YES</u></p> <p>On your inspection form, note the annulus and tubing pressures recorded after 15 minutes.</p> <p>Have the operator shut the well in for 2 hours, and if possible, bleed pressure from the injection tubing. Record the tubing and annulus pressure after two hours.</p> <p>Bleed off the annulus for 60 seconds. Record the tubing and annulus pressures after bleed-off, and estimate the volume bled off.</p> <p>INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.</p> <p>END PROCEDURE.</p>	<p><u>NO</u></p> <p>Require the operator to monitor and report to EPA with the annulus and tubing pressures for at least 14 days to see if pressure returns to the annulus.</p> <p>Instruct the operator to contact EPA as soon as any pressure returns to the annulus.</p>
<p><u>DOES PRESSURE RETURN TO THE ANNULUS WITHIN 14 DAYS?</u></p>	<p><u>YES</u></p> <p>EPA Technical Expert will design a proper Mechanical Integrity test.</p> <p>Compliance officer will require the operator to conduct the test within 14 days.</p>	<p><u>NO</u></p> <p>The well is considered to have mechanical integrity.</p> <p>END PROCEDURE.</p>
<p><u>Does the Well Pass the MIT?</u></p>	<p><u>YES</u></p> <p>Require the operator to monitor and report to EPA with the annulus and tubing pressures for at least 14 days to see if pressure returns to the annulus.</p>	<p><u>NO</u></p> <p>INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.</p>



	Instruct the operator to contact EPA as soon as any pressure returns to the annulus.	END PROCEDURE.
<u>Does Pressure Return to the Annulus Within 14 Days?</u>	<p><u>YES</u></p> <p>EPA Technical Expert will design a proper Monitoring Program to determine the cause of recurrent annular pressure.</p> <p>Compliance officer will require the operator to begin the Monitoring program within 14 days.</p> <p>Conduct unannounced inspections at the well during the Monitoring Program.</p>	<p><u>NO</u></p> <p>The well is considered to have mechanical integrity.</p> <p>END PROCEDURE.</p>
<u>Is the Annulus Pressure Caused by Temperature?</u>	<p><u>YES</u></p> <p>EPA Technical Expert will design a proper Temperature Monitoring Program that allows injection to continue while tracking relationship between temperature and recurrent annulus pressure.</p> <p>Compliance officer will require the operator to cease injection immediately if the operator fails to follow the Temperature Monitoring Program.</p> <p>Compliance officer will require the operator to cease injection immediately if recurrent annular pressures cannot be explained by the results of the Temperature Monitoring Program.</p> <p>Compliance officer will require annual Mechanical Integrity Tests using the standard pressure method.</p>	<p><u>NO</u></p> <p>INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.</p> <p>END PROCEDURE.</p>



14-DAY PRESSURE MONITORING

Please use this form to report data for a 14-day period after pressure is bled from the tubing-casing annulus. Please telephone EPA in Denver as soon as possible when/if pressure returns to the annulus. This data will be used to determine the cause(s) of recurrent annular pressure.

NOTE: DO NOT BLEED PRESSURE FROM ANNULUS DURING THE 14-DAY MONITORING PERIOD.

	DATE	TIME	ANNULUS PRESSURE (psi)	TUBING PRESSURE (psi)	WELL INJECTING (YES/NO)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					

WELL NAME: _____

OPERATOR: _____

SIGNATURE: _____

DATE: _____



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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VIII

999 18th STREET - SUITE 300
DENVER, COLORADO 80202-2466

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 37
Demonstrating Part II (external) Mechanical Integrity
for a Class II injection well permit.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

During the review for a Class II injection well permit, consideration must be given to the mechanical integrity (MI) of the well. MI demonstrates that the well is in sound condition and that the well is constructed in a manner that prevents injected fluids from entering any formation other than the authorized injection formation.

A demonstration of MI is a two part process:

PART I - **INTERNAL MECHANICAL INTEGRITY** is an assurance that there are no significant leaks in the casing/tubing/packer system.

PART II - **EXTERNAL MECHANICAL INTEGRITY** demonstrates that after fluid is injected into the formation, the injected fluids will not migrate out of the authorized injection interval through vertical channels adjacent to the wellbore.

A Class II injection well may demonstrate Part II MI by showing that injected fluids remain within the authorized injection interval. This may be accomplished as follows:

- 1) Cement bond log showing 80% bond through the appropriate interval (Section Guidance 34),
- 2) Radioactive tracer survey conducted according to a EPA-approved procedure, or
- 3) Temperature survey conducted according to a EPA-approved procedure (Section Guidance 38).

For each test option above, the operator of the injection well should submit a plan for conducting the test. The plan will then be approved (or modified and approved) by EPA. EPA's pre-approval of the testing method will assure the operator that the



test is conducted consistent with current EPA guidance, and that the test will provide meaningful results.

Part II MI may be demonstrated either before or after issuing the Final Permit. However, if Part II is to be demonstrated after the Final Permit is issued, a provision in the permit will require the demonstration of Part II MI. The well will also be required to pass Part II MI prior to granting authorization to inject.

Radioactive tracer surveys and temperature surveys require that the well be allowed to inject fluids as part of the procedure. In these cases, a well that has shown no other demonstration of Part II MI will be allowed to inject only that volume of fluid that is necessary to conduct the appropriate test.

After the results of the test proves that the well has passed Part II MI, the well will be given authorization to begin full injection operations.

If any of the tests show a lack of Part II MI, the well will be repaired and retested, or plugged (See Headquarters Guidance #76).





UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION VIII

999 18th STREET - SUITE 300
DENVER, COLORADO 80202-2466

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 39

Pressure testing injection wells for Part I (internal)
Mechanical Integrity

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

- (1) There is no significant leak in the tubing, casing or packer; and
- (2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the down hole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which



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would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required at least every five (5) years. If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. The Regional UIC program must be notified of the workover and the proposed date of the pressure test. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate. Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;
2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);
3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;
4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter



depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and
6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

Test Criteria

1. The duration of the pressure test is 30 minutes.
2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.
3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.
4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form and a pressure recording



chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.
2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.
3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.
4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.
5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:



6. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.
7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.
8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.
9. Hook-up well to pressure source and apply pressure until test value is reached.
10. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.
11. Record tubing and annulus pressure values every five (5) minutes.
12. At the end of the test, record the final tubing pressure.
13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.
14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.



15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these exceptional or extraordinary conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Attachment





UNITED STATES
ENVIRONMENTAL
PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 300

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 38

Using temperature surveys to determine Mechanical Integrity for a Class II injection well that has tubing cemented inside casing.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

The purpose of this guidance is to provide a standard logging procedure when using temperature logs to determine MI in a Class II injection well that has tubing cemented inside casing. It may also used to verify confinement within the injection formation.

LOGGING PROCEDURE

Run the temperature survey going into the hole with the temperature sensor located as close to the bottom of the tool as possible. The tool need not be centralized.

Record temperatures at 1-5NF per inch, on a 5" per 100 ft. log scale.

Logging speed should be within 20 - 30 ft/min.

Run the log from ground level to total depth (or plug-back depth) of the well.

When using digital logging equipment, use the highest digital sampling rate possible. Filtering should be kept to a minimum so that small-scale results are obtained.

Record the first log trace while injecting at the maximum allowed injection pressure. Subsequent to the temperature survey, maximum injection pressure will be limited to the pressure used during the survey.

LOG TRACES

Record the first log trace while the well is actively injecting, recording traces for gamma ray, temperature, and differential temperature.

Shut-in (not injecting) temperature curves should be recorded at intervals depending on the length time that the injection well

has been active. Preferred time intervals are shown in the following table:

ACTIVE INJECTION	RECORD SHUT-IN CURVES AT THESE TIMES (HRS)				
1 MONTH	1	3	6	12	
6 MONTHS	1	6	10-12	22-24	
1 YEAR	1	10-12	22-24	45-48	
5 YEARS	1	10-12	22-24	45-48	90-96
10 YEARS OR MORE	1	22-24	45-48	90-96	186-192

FCD:August 9, 1995:RCT/RCT/k:\guidance.38



**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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**Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing
near Injection Perforations**

PURPOSE:

The purpose of this document is to provide EPA staff with guidelines to assist operators in planning and conducting a Radioactive Tracer Survey (RTS). When used properly, a RTS can identify the presence or absence of vertical fluid movement behind the casing near injection perforations. With the exception of very specific circumstances, the RTS is not approved as a stand-alone method for demonstrating Part II (external) Mechanical Integrity (MI). However, a RTS can be used to supplement data from approved Part II demonstrations. If channeling behind casing is detected, a RTS can also be used to evaluate the vertical extent of fluid movement.

As with any logging or testing method, planning a RTS should begin with a clearly stated objective and should identify consequences and follow-up actions based on the results anticipated. It is important to understand the site-specific geologic, construction, and operational factors that may influence the test. Remind the operator that RTS results must be analyzed and interpreted by a knowledgeable log analyst and must be documented with the appropriate narrative descriptions, log records, schematics, and charts, and that advance notification is required 30 days prior to conducting a RTS when it is expected that the Maximum Allowable Injection Pressure (MAIP) will be exceeded. Discussing the RTS procedure with the operator and the logging service company prior to conducting the RTS is strongly recommended.

PLANNING THE TEST

The operator should consider many factors when planning a RTS: wellbore construction, any drilling or completion problems encountered, fracture and acid treatments, proximity of USDWs and confining zones, and the adequacy of the confining zone all play a role in the success of the test. Planning the RTS should include discussion of the following items with the operator and the logging service company:

- **LOGGING EQUIPMENT:** Determine any limitations of the logging equipment to be used in conducting the RTS.
- **THE LOGGING TOOL:** The RTS tool should include a collar locator for depth control with at least one ejector and one gamma-ray detector located below the ejector.
- **TRACER MATERIAL:** The tracer material, typically Iodine 131, should be dated less than one half-life at the time of use.
- **TEST PRESSURE:** Discuss the test pressure with the operator and the service company prior to conducting the RTS. The results obtained are only valid at (or below) the pressure obtained while conducting the RTS. Therefore, the RTS should be conducted at the MAIP when possible. The MAIP may be reduced in cases where a RTS is conducted at a lower pressure.

close as possible to the top set of effective perforations but at a depth that will allow the radioactive slug to pass entirely below the lower detector before entering the perforations. If the detector is located too close to the perforations, the tool may detect tracer material inside and outside of the casing at the same time, obscuring the results of the test.

Once the tool is positioned, a tracer slug is ejected into the wellbore where it mixes with injected fluid and begins moving downward inside the casing, past the lower detector as it continues toward the perforations. The tool should remain on time-drive as the tracer slug enters the perforations and continue recording for some predetermined time, waiting for evidence of any tracer material moving vertically outside of the casing.

Calculating an appropriate wait-time is crucial for using the RTS to determine if fluid is moving vertically behind casing. The wait-time depends on several factors: 1) the injection rate, 2) the distance between the detector and the perforations, 3) the percentage of fluid moving into the perforations, and 4) the size of any cement channel (which cannot be predetermined). No single wait-time will fit every case, but one hour is the safest default for the majority of injection wells in Region 8. Another method for determining the appropriate wait-time is to use a value of $3t$, where t is the time for fluid inside casing to flow between the detector and the uppermost set of effective perforations. A full discussion of the methodology used to determine an appropriate wait-time should be included as part of the submitted results. In addition, a written justification of the chosen wait-time may be in the operator's interest, particularly if the selection methodology differs from those outlined in these guidelines.

The following considerations apply for a Channel Check utilizing Time Drive:

- The results of the Injectivity profile should be used to determine the uppermost set of perforations accepting fluid and the fraction of fluid entering those perforations.
- The log trace during this first portion of the Channel Check should be made with the tool stationary on time-drive, and with the tool located so that the lower detector is as close as possible to the uppermost set of effective perforations, but at a sufficient distance that will allow the radioactive slug to pass entirely below the lower detector before entering the perforations. It may be preferable to position the tool at a specific depth (the confining zone, for example, if it is close enough to the perforations).
- The operator should use a default wait-time of one hour or calculate $3t$. If site-specific conditions appear to call for longer or shorter test times, discuss this with the operator and with the service company prior to running the RTS.
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- b) **Depth Drive:** Immediately following the time-drive portion of the channel check, the tool should be switched to depth-drive and the interval between the tool's

current depth and the perforations should be logged. If the detector indicates any tracer material moving vertically away from the perforations, the operator should wait briefly and then repeat this pass, tracking the slug as it continues to move vertically. Several passes may be required in order to determine the depth where the slug appears to move no further. If movement of the slug is detected behind casing in the depth-drive mode, the operator will include a full written description of the extent and the probable causes for the fluid movement, including any justification of why the results indicate the presence of adequate cement despite observed channeling may be in the operator's interest.

- 6) **Post-tracer gamma ray log:** This log provides a post-tracer gamma ray log to be compared with the pre-tracer baseline gamma ray log recorded prior to running the RTS. Evidence of behind-pipe fluid movement can be evaluated by overlaying and comparing these two log traces, noting any differences or 'hot spots'.

- Logging speed, gain, and depths run should duplicate settings used for the pre-tracer baseline gamma ray log

SUBMITTING THE RESULTS:

The operator should provide an analytical interpretation of the logging results performed by a qualified analyst. This should include a written description of the procedure including the methodology used to calculate the wait-time, and conclusions drawn from the test. The submittal should include a fluid loss profile across the perforations and a schematic diagram of the RTS tool and well construction on or with the log. The diagram should show:

- Tool layout
- Casing diameters and depths
- Tubing diameter and depth
- Perforated interval(s)
- Open hole intervals
- Packer location(s)
- Total depth and/or plugged back total depth
- The location of the tool when the tracer material was ejected.
- The distance the tracer slug appears to have moved.
- All stationary tests conducted.
- Detector depth and the amount of time elapsed during the test.

ADDITIONAL CONSIDERATIONS:

Ejection of tracer material should occur as close to the perforations as possible. This may help to minimize the occurrence of radioactive material adhering to the inside casing wall or recirculating below a packer, creating 'hot spots' which could be misinterpreted as evidence of fluid movement. In most cases, there is no UIC Permit requirement to use the RTS for a packer check, so eliminate the packer check whenever possible to prevent misinterpretation.